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Environmental Analysis of Biomass-to-Ethanol Facilities

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ACRONYMS AND ABBREVIATIONS

AD	anaerobic digestion
ADM	Archer Daniels Midland
APC	air pollution control
APHIS	Animal and Plant Health Inspection Service
ASTM	American Society for Testing and Materials
BACT	best available control technology
BAT	best available technology
BIF	boiler and industrial furnace
BL1-LS	Biosafety Level 1—Large Scale
BL2-LS	Biosafety Level 2—Large Scale
BL3-LS	Biosafety Level 3—Large Scale
BOD	biochemical oxygen demand
CAAA-90	Clean Air Act Amendments of 1990
CDD	chlorodibenzo-p-dioxin
CDF	chlorodibenofuran
CEMS	continuous emission monitoring system
CFR	Code of Federal Regulations
CI	carbon injection
CIC	Clement International Corporation
CO	carbon monoxide
CO_2	carbon dioxide
COD	chemical oxygen demand
CTG	control technology guideline
CWA	Clean Water Act
DDGS	distillers dried grains and solubles
DRE	destruction and removal efficiency
DSI	dry sorbent injection
dtpd	dry tons per day
EA	environmental assessment

ACRONYMS AND ABBREVIATIONS

EIS	environmental impact statement
EP	emissions parameter
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
FBC	fluidized bed combustor
FDA	Food and Drug Administration
FF	fabric filter
FGD	flue gas desulfurization
FIFRA	Fungicide and Rodenticide Act
FONSI	Finding of No Significant Impact
FSI	furnace sorbent injection
FSIS	Food Safety Inspection Service
GCP	good combustion practice
GILSP	Good Industrial Large Scale Practice
GLSP	Good Large Scale Practice
H_2S	hydrgen sulfide
HAP	hazardous air pollutant
HC	hydrocarbon
HCl	hydrogen chloride
HMF	hydroxy methyl furfural
IDEM	Indiana Department of Environmental Management
LAER	lowest achievable emissions rates
MACT	maximum achievable control technology
MMBtu	million British thermal units
MSW	municipal solid waste
MWC	municipal waste combustor
NAAQS	national ambient air quality standards
NECI	New Energy Company of Indiana
NEPA	National Environmental Policy Act

ACRONYMS AND ABBREVIATIONS

NESCAUM	Northeast States Coordinated for Air Use Management
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
O_3	tropospheric ozone
OECD	Organization for Economic Cooperation and Development
OS	occupational standards
PM	particulate matter
PMN	Pre-Manufacture Notice
POTW	publicly owned treatment works
ppmv	parts per million by volume
ppmvd	parts per million by volume, dry
ppmvd @ 15% O_2	parts per million by volume, dry, corrected to 15% oxygen
PSD	Prevention of Significant Deterioration
RA	risk assessment
RACT	reasonably available control technology
RCRA	Resource Conservation and Recovery Act of 1976
RDF	refuse-derived fuel
SD	spray dryer
SIP	state implementation plan
SNCR	selective non-catalytic reduction
SNUR	Significant New Uses Rule
SO_2	sulfur dioxide
SSF	simultaneous saccharification and fermentation
TCLP	toxicity characteristic leachate procedure
TEQ	toxic equivalency
TS	total solids
TSCA	Toxic Substances Control Act

ACRONYMS AND ABBREVIATIONS

TSS	total suspended solids
USDA	U.S. Department of Agriculture
VOC	volatile organic compound

Executive Summary

This report analyzes the environmental regulatory requirements for several process configurations of a biomass-to-ethanol facility. It also evaluates the impact of two feedstocks (municipal solid waste [MSW] and agricultural residues) and three facility sizes (1000, 2000, and 3000 dry tons per day [dtpd]) on the environmental requirements.

The basic biomass ethanol process has five major steps:

1. Milling,
2. Pretreatment,
3. Cofermentation,
4. Enzyme production,
5. Product recovery.

Each step could have environmental impacts and thus be subject to regulation. Facilities that process 2000 dtpd of MSW or agricultural residues would produce 69 and 79 million gallons of ethanol, respectively. The overall basic process flow diagram is shown in Figure ES-1.

From this basic process, four scenarios, which differ primarily in the solids handling and utilities, have been developed:

Scenario A (base-case configuration)

- The unreacted solids from the process are burned in a circulating fluidized bed (CFB) boiler
- On-site wastewater treatment consists of anaerobic digestion (AD) followed by aerobic treatment. The AD process converts much of the organic content of the wastewater into methane, carbon dioxide, and water. Some hydrogen sulfide is also produced from sulfates. This biogas is also combusted in the boiler.
- Several fermentation by-products, such as fusel oils and acetaldehyde, are concentrated and burned in the boiler. For a facility that processes 2000 dtpd of MSW, the boiler would have a heat input of almost 580 MMBtu/h. A facility of the same size that processes agricultural residues would have a boiler of about 625 MMBtu/h.

Scenario B

- The utility section is simplified by eliminating the boiler
- All wastes and fermentation by-products are sent off-site for treatment or disposal, or both
- The AD system is eliminated because significant quantities of methane are generated.

Scenario C

- The boiler and AD system are added back in
- Instead of separating out the solids before AD, the entire effluent is sent to the digester
- Biogas from the digester is again combusted in the CFB. Most solids will be converted to biogas, so emissions are expected to be lower.

Scenario D

- The boiler is replaced by an integrated combined cycle gasification system
- All solids and fermentation by-products are sent to the gasifier
- Wastewater treatment is the same as for the base case
- The biogas streams from the gasifier and from the digester are sent to a gas turbine to generate electricity
- The flue gas from the turbine is sent to a steam generator and waste heat recovery boiler to generate more electricity and process steam. For a 2000-dtpd facility that processes MSW,

the gas turbine would have a heat input of almost 340 MMBtu/h (lower heating value).

Regulatory Analysis

Air regulations are expected to have the greatest impact on biomass-ethanol facilities. The primary federal air regulations applicable to these facilities are the 1970 Clean Air Act and all subsequent amendments, especially the 1990 Clean Air Act Amendments (CAAA-90). The U.S. Environmental Protection Agency (EPA) is currently developing regulations to address CAAA-90.

The regulatory status of a facility depends, in part, on its location. Facilities can be located in attainment areas (regions that meet national ambient air quality standards [NAAQS] for the six "criteria" pollutants—tropospheric ozone [O_3], carbon monoxide [CO], particulate matter [PM] less than 10 µ in diameter, sulfur dioxide (SO_2), nitrogen dioxide, and lead). They may also be located in nonattainment areas (regions that do not attain the NAAQS for one or more pollutants). Many U.S. metropolitan areas are nonattainment areas, especially for O_3.

The EPA has promulgated Prevention of Significant Deterioration (PSD) requirements to permit plants in attainment areas. PSD reviews are required for new or modified projects in attainment areas that have emissions greater than the threshold limits for any criteria pollutant. PSD threshold limits for new sources are 250 tons per year (tpy) for any criteria pollutant, except lead. PSD review requirements include best available control technology (BACT) assessments and air quality dispersion modeling. A BACT assessment (in conjunction with the air dispersion modeling) determines the level of air pollution required. In any case, the level of pollution cannot violate new source performance standards (NSPS), and the air pollution control (APC) must be at least as stringent as the NSPS, if applicable. Many states have separate BACT reviews that are significantly more stringent than federal BACT requirements. Thus, BACT review may be required for emission levels that are significantly below PSD Review Threshold Limits.

In nonattainment areas, new sources of the criteria pollutants must install controls to meet the lowest achievable emission rate (LAER). Emission offsets equal to or greater than the proposed emission rate may also be required. These are pollutant-specific regulations, so only those pollutants for which the region does not attain the NAAQS are required to meet LAER or emissions offsets.

Title III of CAAA-90 regulates 89 pollutants classified as hazardous air pollutants (HAPs). These regulations are not on a pollutant basis (as are the PSD regulations), but are regulated by industry. Major HAP sources are stationary sources that emit 10 tpy of any one HAP or 25 tpy of all HAPs combined. Electric utility steam-generating units, industrial boilers, and stationary turbines are all potential classes of major sources that may apply to a biomass-ethanol facility. Major HAP sources must apply maximum achievable control technology (MACT), defined as the emission control achievable by the best-performing 12% of existing sources.

MSW combustion is strictly regulated. However, because industrial process and manufacturing wastes are specifically excluded from the definition of MSW (Subpart Ea, 40 CFR 60.50a), the nonreacted solids from a biomass-to-ethanol facility would probably not be considered MSW. MSW biomass-to-ethanol facilities would therefore not have to meet standards for MSW combustors. More importantly, the public probably would not perceive MSW biomass-to-ethanol plants as waste-to-energy facilities. However, some states may classify the waste fuel from the ethanol plant as MSW or require APCs similar to those required for an MSW combustor. Thus, an MSW biomass-to-ethanol plant is assumed to meet the MSW combustor regulatory requirements.

Existing and new MSW combustors are regulated. Facilities built before December 1989 have the least stringent regulations; those built after September 1994 have the most stringent. Facilities built between 1989 and 1994 have requirements in between the others. Depending on the potential location, co-locating a biomass-to-ethanol plant with an already permitted MSW combustor may be advantageous. However, APC costs would probably not be the determining factor in this decision unless the facility were small (less than 225 Mg/d). Table ES-1 summarizes the emission standards and proposed air pollution controls for facilities built before December 1989 and after September 1994.

In addition to the pollutants outlined below, facilities constructed after 1989 must also meet emission limits for nitrogen oxides (NO_x), and metals such as cadmium and lead. Thus, the emission regulations become more stringent the later the facility is built, not only in overall emission rates, but also in the number of pollutants monitored and the size of facilities regulated.

Table ES-1
Emission Regulations for Existing and New MSW Combustors

	CO	Organics (total dioxin/furan)	Metals as PM	SO_2	HCl[1]	Opacity
Plants Built before 1989						
> 1000 Mg/d	100 ppmvd	60 ng/dscm	34 Mg/dscm	30 ppmvd or 70% control	25 ppmvd or 90% control	10%
> 225 Mg/d	100 ppmvd	125 ng/dscm	69 Mg/dscm	30 ppmvd or 50% control	25 ppmvd or 50% control	10%
APC[5]	GCP	GCP[2], SD[3], and ESP for > 1000 Mg/d DSI and ESP for > 225 Mg/d	ESP	SD/ESP > 1000 Mg/d DSI[4]/ESP > 225 Mg/d	Same as for SO_2	ESP
Plants Built after 1994						
> 225 Mg/d	100 ppmvd	13 ng/dscm or 0.2 ng/dscm TEQ[8]	15 Mg/dscm	30 ppmvd or 80% control	25 ppmvd or 95% control	10%
> 35 Mg/d	same	same	same	same	same	same
APC	GCP	GCP, SD/FF[6]	SD/FF/CI[7]	SD/FF/CI	SD/FF/CI	SD/FF/CI

1 Hydrogen chloride
2 Good Combustion Practice
3 Spray Dryer
4 Dry Sorbent Injection
5 Air Pollution Control
6 Fabric Filter
7 Carbon Injection
8 Toxic Equivalency

Many states have regulations for toxic emissions such as arsenic, dioxins, and nickel, from MSW combustors. These standards are usually in the form of ambient concentrations at ground level that have been developed based on health risk assessments. States with requirements for conducting a health risk analysis for toxic pollutants can make permitting more difficult, as very few people want their cancer risks calculated, even if they are low.

Regulations for new MSW plants are stricter than those for existing plants, but the pollution control requirements, (except for the NO_x standard), are about the same. Thus, cost would probably not be a deciding factor on whether to use an existing MSW combustor. However, permitting and siting any new plant, especially an MSW combustor, can be very difficult and should be considered when evaluating co-location opportunities.

Gas Turbine Regulations

Scenario 3 includes gasifying the post-fermentation nonreacted solids. Existing and new integrated gasifier combined cycle plants are regulated. Existing facilities must meet Reasonably Available Control Technology (RACT) limits for core boilers for their NO_x emissions and CAAA-90 Phase 1 criteria emissions for SO_2. RACT limits are also under development for CO and hydrocarbons (HCs); metal emissions standards will be set with the HAP regulation. New facilities must meet NSPS limits for NO_x and SO_2; CO and HC standards are under development.

Regulations for Agricultural Residues

The primary federal regulations that apply to the biomass-to-ethanol facility using agricultural residues apply to combustors. Existing and new combustors are regulated, and new combustors have more stringent regulations. Because the nonreacted solids from the facility are not a listed fuel in NSPS, there are no specific federal emission regulations, and the facility would likely need to comply only with the general requirements, such as reporting requirements, of the NSPS. Most states, however, would require specific emission limits. If the facility is located in a nonattainment area, it would need to implement RACT for existing sources and LAER for new sources. Finally, industrial and commercial boilers are a source category under the HAP regulations and thus will be subject to MACT requirements; large electric utility steam-generating units may also be subject to MACT requirements.

Solid Waste Regulations

Solid waste in the United States is regulated at the federal level under the Resource Conservation and Recovery Act (RCRA). *Solid waste* is a regulatory term that defines generally who generates the waste, and has no correlation with the physical state of the waste. A waste can be considered hazardous under RCRA if it has any or all of the four following characteristics:

- Toxicity
- Reactivity
- Corrosivity
- Ignitability.

Most states have EPA authority to operate their own hazardous waste programs and adopt their own regulations, but they must be at least as stringent as the federal regulations.

Two sets of RCRA regulations—those that govern the combustion of hazardous wastes in boilers and industrial furnaces (BIFs), and those that govern the disposal of bottom ash from incinerators and boilers— could have a major impact on biomass-to-ethanol facilities.

Combustion of process by-products such as acetaldehyde in the boiler may be subject to RCRA regulations, as acetaldehyde is considered hazardous. Under new RCRA regulations, BIFs will now have to meet many of the same requirements as do hazardous waste incinerators. Hazardous waste incinerator permits are among the toughest EPA permits to obtain, and BIF permits may be equally hard to obtain under the new regulations. Because future BIF standards and permitting requirements are envisioned to be very stringent (similar to existing hazardous waste permits), biomass-to-ethanol facilities should be designed to avoid having to meet the BIF regulatory requirements. Three methods under the existing federal regulations could provide regulatory relief from BIF requirements for biomass-to-ethanol facilities:

- The small-quantity on-site burner exemption that allows operators of facilities that burn hazardous waste in an on-site boiler to be exempt from most BIF regulations. To qualify, the hazardous waste must have a minimum heating value of 5000 Btu/lb and "not exceed one percent of the total fuel requirement for the boiler on a total heat input or mass input basis, whichever results in the lower mass feed rate of hazardous waste" (40 CFR 266.108).

- The low-risk waste exemption or the waiver for destruction and removal efficiency trial burn. Qualifying, however, depends on how a specific state interprets and enforces RCRA, because the nonreacted solids fuel burned in the boiler would need to meet certain specifications such that it was nonhazardous and burned similarly to a fossil fuel (40 CFR 260.109).

- Classify the by-product fuels as clean fuels. In the currently proposed regulation scheme, energy recovery from clean fuels would be exempt from BIF regulations. Standards for clean fuels have not been finalized, but they are expected to have requirements on heating value, composition, and the type of combustion products generated. Acetaldehyde, fusel oils, and methane may all fall into this category.

Because MSW combustor ash is not subject to RCRA regulation as a hazardous waste, EPA would not consider the bottom ash (i.e., ash from the boiler) from CFBs in MSW biomass-to-ethanol facilities a hazardous waste. Most states do not define MSW bottom ash as hazardous, although some regulate it as a special handling waste, which is somewhere between the two classifications. The requirements for managing a special handling waste vary, but generally include adequate safeguards on fugitive emissions, such as spraying ash piles to prevent fugitive dust emissions, and disposal in a special lined monomer (an isolated part of a landfill, but not a hazardous waste landfill). The MSW processed in a biomass-to-ethanol facility will likely be sorted (similar to refuse-derived fuel [RDF]), the ash will probably not be hazardous.

The above regulations apply to MSW that has not been sorted or processed in any way. Combustion ash from agriculture residue CFBs would be less likely to contain metals and so it, too, would be exempt from hazardous waste regulations. Thus, ash from CFBs from biomass-to-ethanol facilities based on MSW or agricultural residues is not considered hazardous.

State regulations vary greatly on their definition of a solid waste, which can have an enormous impact on the air quality standards a facility must meet. A biomass-to-ethanol facility that uses agriculture residues as a feedstock would probably be regulated as an industrial facility that burns process wastes in a boiler, but states could also regulate it as a waste wood combustor. Wood waste combustion regulations vary depending on whether the wood is treated or untreated, and facility location. Treated wood combustors generally have more stringent regulations (similar to those for MSW combustors) than combustors that use untreated wood. In California, however, all wood combustors are subject to the same regulations as MSW facilities.

Water Regulations

Under the Clean Water Act, EPA has cooperated with states to establish discharge standards for specific pollutants from industrial facilities. These limits are based on the best available technologies and the economic costs of compliance. The EPA enforces compliance through a permitting system run by individual states under the National Pollutant Discharge Elimination System (NPDES), and has established standards that apply to specific industries, including steam generating units, to control 129 toxic pollutants.

The regulations for NPDES permits are not discussed because this analysis assumes all wastewater discharges would go to a publicly owned treatment works (POTW); avoiding the NPDES permit is a benefit because it can be time consuming to obtain.

Recent regulations restrict hazardous waste discharges to POTWs. These regulations include restrictions on the type of waste that can be discharged by an industrial facility to a POTW and notification requirements for industrial facilities that discharge more than 15 kg of nonacute hazardous waste per month to a POTW. The new regulations prohibit any discharges of petroleum oil, nonbiodegradable cutting oil, or products of mineral-oil origin in amounts likely to interfere with pass-through treatment systems.

The new regulations specify a minimum level of control that POTWs must apply in dealing with significant industrial users, which includes facilities that:

- Are subject to a categorical pretreatment standard (40 CFR Part 403)

- Discharge an average of 25,000 gallons/day of process water (excluding sanitary, noncontact-cooling, and boiler-blowdown wastewaters)

- Are designated "significant" dischargers by the POTW because their discharges may adversely affect POTW operations.

Minimum control mechanisms that include effluent limits based on general pretreatment standards, categorical pretreatment standards, local limits, and state and local laws are required of all significant users.

The Clean Water Act (CWA) is currently up for reauthorization in Congress, so new regulations could make pollutant discharges more strict. New limitations on toxic pollutant discharges will most likely be included in the CWA reauthorization. For example, toxic discharges of arsenic, nickel, cadmium, lead, and selenium can exceed the established water quality criteria for coal-fired power plant sources and thus may be subject to stricter discharge permit restrictions (ENSR 1991).

The National Environmental Policy Act

The National Environmental Policy Act (NEPA) provides a mechanism for environmental review of federal activities. NEPA continues to be a primary basis for challenges to public and private development decisions, and is important to environmental activists because it gives a statutory basis to force review of federal decisions.

Federal actions include operating programs, constructing facilities, and providing funding to others to perform actions that affect the environment. Actions that require federal money or require a permit from a federal agency are subject to NEPA. Under NEPA, the applicable agency must evaluate the action to determine the type of analysis that must be prepared. Some actions, such as writing a report, are categorically excluded from NEPA because they will never have significant impacts. Others are subject to the environmental assessment requirements to determine whether a finding of no significant impact can be awarded or if a detailed Environmental Impact Statement (EIS) must be prepared. Preparing an EIS can incur significant costs and bring the public into the decision-making process. Thus, it generally increases the permitting time for a facility.

States may have their own state environmental quality act reviews, which can be more stringent than the federal requirements.

Regulation of Biotechnology

The basis for regulating the domestic biotechnology industry is the 1986 Coordinated Framework for the Regulation of Biotechnology. Under this framework, jurisdiction for regulating the biotechnology industry is divided among three federal agencies: the Food and Drug Administration (FDA), the U.S. Department of Agriculture (USDA), and EPA. Because the current biomass-to-ethanol process design includes a recombinant *Escherichia coli* to ferment pentose sugars, EPA would have jurisdiction over the facility under the provisions of the Toxic Substances Control Act (TSCA). If the design were changed to include an animal feed as a by-product, USDA review would also be required.

The TSCA is designed to regulate harmful chemical substances. Under TSCA, microorganisms are considered chemical substances, and any person who intends to manufacture or import a new chemical substance must first submit a Pre-Manufacture

Notice (PMN) to EPA. The EPA will then perform a risk-benefit analysis to determine whether the risk to human health or to the environment outweighs the benefits.

A new chemical substance is not listed on TSCA's Inventory of Chemical Substances. The EPA considers intergeneric (containing DNA from different genera) microorganisms new chemical substances if they are not already listed on the TSCA Inventory of Chemical Substances. New intrageneric microorganisms that are formed through genetic engineering are not considered new chemical substances, and thus are not subject to PMN (CIC 1993). Similarly, naturally occurring microorganisms are assumed to be on the Inventory and as such are exempted from PMN (CIC 1993).

Use of intergeneric organisms in contained systems (such as those used for fuel or enzyme production) would be subject to PMN. The EPA has considered exempting this class (or a specific subset) from the PMN requirements, but this has not yet occurred (Korwek 1990) and will probably not occur soon.

The EPA is currently looking at revising the TSCA to better address the biotechnology industry. Primarily, the proposed modification would be a tier testing scheme for new biotechnology applications. The schemes would then be used to generate hazard and exposure data for risk assessments (McMillan and Finkelstein 1994).

The 1986 Coordinated Framework also provided guidance on containing recombinant microorganisms in large-scale fermentations. The current guidelines (*Federal Register* 1991) include four containment levels:

- Good Large Scale Practice (GLSP)
- Biosafety Level 1—Large Scale (BL1-LS)
- Biosafety Level 2—Large Scale (BL2-LS)
- Biosafety Level 3—Large Scale (BL3-LS).

In general, GLSP standards describe a level of physical containment for large-scale research or production that involve viable, nonpathogenic, and nontoxigenic recombinant strains derived from host organisms that have an extended history of safe large-scale use. The higher containment levels are based on laboratory containment levels.

These standards are only guidelines, but they are widely accepted by industry and the Organization for Economic Cooperation and Development (McMillan and Finkelstein 1994). A current problem with the standards, however, is that EPA has designated very few organisms that meet the criteria for GLSP. Identifying organisms that meet these criteria would reduce the need for advanced tier testing (McMillan and Finkelstein 1994).

Odor Control

Several process areas in a biomass-to-ethanol facility (such as fermentation, feedstock storage, and wastewater treatment) can generate odors. Controlling potential odors is very important to the overall success of a biomass-to-ethanol facility. Other industries such as MSW have experienced significant setbacks because of odor concerns.

Odor regulations are generally local (never federal) statutes. Some areas use qualitative standards such as "interfering with life or property" to control odor. Such statutes are difficult to address. Other communities, however, have developed quantitative odor standards, which generally result in a system that is easier to implement and provides a framework for working with the community.

Several methods of controlling odors, such as absorption and condensation, are available. Depending on the odor concentration and source, some methods are more effective than others. Odor management is an important component of the biomass-to-ethanol process and should be included in the earliest stage of planning and design. The current biomass-to-ethanol design has several odor control strategies already included, but a more detailed study of odor concerns, including developing a plan for community involvement is warranted.

Summary of Environmental Regulatory Analysis

The federal environmental regulations that govern the biomass-to-ethanol process are summarized in Table ES-2. The table also shows the estimated regulatory burden for each emission type; this is based on experience with similar types of facilities and correspondence with EPA.

Because state environmental agencies interpret EPA regulations differently, there is no way to exactly determine how a biomass-to-ethanol facility would be regulated until a permit application is submitted. Estimating regulations for new facilities is also difficult, because no precedent has been set.

Environmental Considerations for the Current Fuel Ethanol Industry

Environmental considerations for fuel ethanol facilities are generally the same as those for most other manufacturing facilities: air emissions, water releases, odor, and solid waste disposal. The greatest potential impacts from these facilities are probably air and water emissions.

The major sources of air emissions are the boiler flue gas, feedstock processing, by-product recovery and processing, fermentation off-gases, solvent storage, distillation, and fuel processing (Collins et al. 1980). The boiler generally is the greatest source of air pollution in a fuel ethanol facility. With proper controls, however, all pollutants can be maintained at lower than applicable emission limits.

Wastewater is another important environmental consideration for current fuel ethanol facilities. The major sources of wastewater are by-product processing, distillation/dehydration, APC, cooling tower blowdown, waste treatment effluent, and fuel storage run-off and infiltration.

Releases of solid wastes from fuel ethanol plants include boiler ash, flue gas desulfurization (FGD) solids, and water treatment sludges. The volume of boiler ash and FGD solids will be significantly greater than the sludges. None of the wastes is considered to be hazardous or a difficult disposal issue.

Environmental Case Studies for Actual Fuel Ethanol Facilities

Four facilities were evaluated for their environmental impacts; two are currently operating (Archer Daniels Midland [ADM]-Decatur, and New Energy Company of Indiana [NECI]) and two have shut down (Tennol Energy Company and Agrifuels Refining Company).

Fuel ethanol facilities have many of the same environmental concerns as other manufacturing facilities. The two greatest environmental impacts are air emissions and wastewater releases. Control of regulated air pollutant emissions is readily achievable, and none of the facilities had significant problems in this area. Control of odorous emissions, however, may be more difficult. Odorous releases are a potential unexpected environmental impact for any new fuel ethanol facility and should be addressed in any environmental evaluation.

Adverse impacts to water resources is another potential environmental concern for ethanol facilities. Two of the facilities, NECI and Agrifuels, had significant problems in this area. In both cases, the wastewater was not properly characterized in terms of quantity, quality, odor, and color. ADM, on the other hand, has an extremely successful wastewater treatment system. Not only is the facility able to meet its permitted water limits, but it minimizes water demand by recycling some of the treated water to the process and by using it for irrigation. Good wastewater treatment is essential for the successful operation of any fuel ethanol facility.

Analysis of Environmental Control and Permitting

The most important environmental impacts in terms of permitting and pollution controls from a biomass-to-ethanol facility are the emissions from the CFB or other combustor. Thus, the analysis of pollution control costs and permitting issues will focus primarily on the combustor.

Table ES-2. Preliminary Summary of EPA Regulations for Base-Case Configuration[1]

Process Step	Primary Type of Emissions and Classification	Regulatory Jurisdiction	Expected Regulatory Burden[2]
Fermentation	Ethanol (air)—VOC[3]	CAAA criteria pollutants, State SIP plans for O_3 nonattainment	Low
Product/denaturant storage	Ethanol (air)—VOC	CAAA criteria pollutants, State SIP plans for O_3 nonattainment	Low
Product recovery	Acetaldehyde, fusel oils (mostly liquid phase)— hazardous waste	RCRA boiler rules for hazardous waste combustion, state solid waste regulations	Med/High
Fluidized bed boiler—air emissions	Criteria pollutants (e.g., NO_x, SO_x) and hazardous air pollutants	CAAA (NSPS, PSD, and Title III— Air Toxics), State BACT, RACT, LAER requirements	High
Fluidized bed boiler/APC—ash	Ash (solid waste)	RCRA and state hazardous waste rules	Med/Low[4]
Solids separation	Effluent discharges to POTW	CWA pretreatment standards for effluent discharges	Med/Low

1 Other alternatives will be considered in subsequent sections
2 Evaluated in terms of relative difficulty to obtain permits
3 Volatile organic compound
4 Assumes sorted waste

The base case has four significant sources of air emissions: the fermentation off-gases, the storage tanks, the boiler, and the aerobic wastewater treatment reactor. As shown in Table ES-3, the emissions from all but the boiler are primarily organic compounds and are relatively small. The greatest source of air pollution is the boiler. Table ES-3 presents the expected emissions from a 2000-tpd MSW CFB as well as the corresponding federal regulations, the BACT estimate, the estimated pollution control efficiency for the APC equipment, and the total tpy of criteria pollutants.

In the current design, the amount of hazardous waste (such as acetaldehyde and fusel oils) combusted in the boiler would be less than 1% of the total heat or mass input. Thus, the boiler would be exempt from BIF regulations and would require no major federal solid waste permits. EPA notification of the quantity and type of hazardous waste combusted would still be required, and state regulators could require more stringent review of hazardous waste combustion. The biogas would likely be classified as a clean fuel unless the H_2S level is above applicable levels; clean fuel standards should be checked against projected levels. Ash from the combustor is expected to be similar to ash from an RDF combustor and would thus be nonhazardous.

Table ES-3. Emissions for MSW Base Case

		MSW 2000 tpd New Facility							
		579	MMBtu/h						
	Stream #	**Pollutant**	**Uncontrolled Emission (ppmvd) @ 7% 02**	**Uncontrolled Emission Mg/dscm @ 7% 02**	**Federal Standard**	**BACT Estimate[3]**	**Removal Efficiency**	**Controlled Emission Rate**	**tons/ yr**
air	1	EtOH VOC	57	110	none	CTG'			14
	2	VOCs	na	na	none	CTG			2
	4	NO_x	205	392.000	180 ppm[1]	SNCR	65%	71.75 ppmv	355
		SO_2	190	507.000	30 ppm/80%[1]	SD/FF	80%	38 ppmv	131
		PM-10	na	2900.000	34 Mg/dscm[1]	FF	99%	29 Mg/dscm	76
		lead	1.42E-03	0.012	0.16 Mg/dscm[1]	SD/FF	0.95	7.1E-05 lb/h	0
		CO	126	147.000	100 ppm[1]	GCP	0	126 ppmv	381
		VOCs	37	25.000		GCP	0	37 lb/h	64
		HCl	20	30.000	25 ppm/95%[1]	SD/FF	0.95	1 ppmv	4
		mercury	na	na	0.10 Mg/dscm/80%[1]	C/Na2s inj.	0.8	na	<1
		cadmium	na	na	0.02 m/dscm[1]	SD/FF	0.97	na	<1
		dioxins/furan	na	na	30 ng/dscm[1]	SD/FF	0.97	na	<1
		acetaldehyde	0.21	0.380	none	GCP	0	0.224 lb/h	1
		formaldehyde	0.19	0.230	none	GCP	0	0.14 lb/h	1
solid	3	acetaldehyde	na	na	1% BIF[2]			1.13%[2]	
waste		fusel oils	na	na	BIF-NA			NA	
	5	ash	trace metals	na	TCLP				

1 Based on expected NSPS MSW combustor limits
2 BIF regulations allow maximum firing rate of 1% of total fuel requirements based on BTU or mass basis, whichever results in lower feed rate
3 SD/FF - Spray dryer/ fabric filter; CTG - Control Technology Guidelines (by EPA); SNCR - Selective non-catalytic reduction; C/Na2S inj. - carbon injection; GCP - Good combustion practice

Water discharges from the facility will be sent to a POTW. The treatment system is designed to limit biological oxygen demand levels to 300 Mg/L, chemical oxygen demand to 600 Mg/L, and total suspended solids to 300 Mg/L, levels that are all within POTW requirements.

The environmental releases from Scenario B are generally the same as those for the base case. As there is no boiler, acetaldehyde must be disposed of and the fusel oils will be blended into the ethanol as is common in the corn industry. No major federal air permits would be required, but a state permit would likely be required for the fermentation losses.

All wastes (77,540 tpy) would require landfilling, as they would be assumed nonhazardous. If the water content (50%) of this waste could be reduced, the disposal costs could also be reduced. Acetaldehyde would require disposal as a hazardous waste. Water releases would be similar to the base case, but the aerobic system would need upgrading to handle the larger volumes of waste caused by the elimination of the AD system.

Air emissions from Scenario C are similar to the base case, except for the SO_2 emissions, which are significantly higher because of the higher sulfate load to the anaerobic digester. Because of these higher emissions, the dry scrubber used for the base case may not be feasible, and a wet scrubber followed by a packed tower may be required. A PSD permit would be required in attainment areas. Solid and liquid waste issues would be the same as those in the base case.

The gasification scenario will have significantly lower emissions than the base case. Table ES-4 summarizes these emissions, BACT requirements, and assumed APC efficiencies. Because gasification of unreacted solids is not commercialized, the BACT estimates should be considered preliminary. APC for SO_2, particulates, and NO_x would be required on the gasifier. Because the gas turbine is extremely sensitive to particulates and acid gases, the gas entering the turbine would have to be cleaned to very high standards; thus, the acid gas and particulate emissions from the gasifier would not be of concern from an environmental permitting standpoint.

Char from the gasifier would be disposed of in a landfill. Based on tests from similar units, this material is expected to be nonhazardous.

There are a number of benefits to this scenario from an environmental regulatory standpoint. With appropriate APC equipment, a 2000-tpy facility can avoid the PSD permitting process, and only a state air permit would be required. In addition, this facility would be less likely to be classified as a waste-to-energy facility, as the MSW is not combusted.

Non-boiler emissions such as fermentation are approximately the same from the base case with agricultural residues as from the base case with MSW. Table ES-5 summarizes these emissions. A PSD permit would be required because NO_x and CO emissions would exceed PSD thresholds.

Table ES-4. Emissions Data for Scenario D—Gasification

		MSW 200-tpd New Facility								
		70 366	MMBtu/h combustor MMBtu/h turbine							
	Stream #	Pollutant	Uncontrolled Emission (ppmvd)	Uncontrolled Emission (lb/MMBtu)	Uncontrolled Emission (Mg/dscm)	Federal Standard	BACT Estimate	Removal Efficiency	Controlled Emission Rate	tons/yr
air	1	EtOH (VOC)	57		110	none	CTG			14
	2	VOCs			na	none	CTG			2
	4a[1]	NO_x	186	0.400	357,000	180 ppm	SNCR	65%	65 ppmvd	40
		SO_2	310	0.924	825,000	30 ppm/80%	Wet/Dry[4]	80%	62 ppmvd	53
		PM-10	na	0.030	2700	34 Mg/dscm	Wet/Dry	99%	27 Mg/dscm	9
		lead	1.19E-03	1.15E-05	0.0010	0.16 Mg/dscm	Wet/Dry	0	0.0103 Mg/dscm	<1
		CO	114	0.150	135.000	100 ppm	GCP	0	114 ppmvd	44
		VOCs/HC	34	0.025	22.000		GCP	0	1.65 lb/h	7
		acetaldehyde	0.19	3.86E-04	0.340	1.0%[3]	GCP	0	1.13%	1
		formaldehyde	0.18	2.48E-04	0.220	na	GCP	0	na	<1
	4b[2]	NO_x	42	0.018	81.000	75	GCP	0	42 ppmvd	188
		SO_2	80	0.309	212.000	50 ppm/2.5 lb/MMBtu	none			<1
		PM-10	negligible	negligible	negligible		none			<1
		lead	0	0.000	0.000		none			<1
		CO	10	0.016	11.000		none			26.3
		VOCs	5	0.005	3.300		none			7.8

1 Based on draft NSPS MSW combustor limits
2 Based on NSPS gas turbine regulations
3 BIF regulations allow maximum firing rate of 1% of total fuel requirements based on Btu or mass basis, whichever results in lower feed rate
4 Wet or dry scrubber

Table ES-5. Emissions for the Base Case with Agricultural Residues

		Agricultural 2000 tpd New Facility						
		574	MMBtu/h					
Regulatory Classification	Stream #	Pollutant	Uncontrolled Emission (lb/MMBtu)	Federal Standard	BACT Estimate	Removal Efficiency	Controlled Emission Rate	tons/yr
air	1	EtOH - VOC	na		CTG		3.6 lb/h	16
	2	VOCs	na		CTG		0.53 lb/h	2
	5	NO^x	0.400	0.6 lb/MMBtu[1]	SNCR	65%	0.14 lb/MMBtu	383
		SO_2	0.528	1.2 lb/MMBtu[1]	CFB/Lime	80%	0.10 lb/MMBtu	289
		PM-10*	0.030	2.4 lb/MMBtu[1]	FF	99%	0.024 lb/MMBtu	82
		Lead	7.96E-06	na	CFB/Lime	90%	.79E-06 lb/MMBtu	<1
		CO	0.150	PSD - 250 tpy	GCP	0	0.150 lb/MMBtu	411
		VOCs	0.025	PSD - 250 tpy	GCP	0	0.025 lb/MMBtu	68
		acetaldehyde	3.86E-04	none		0	3.86E-04	1
		formaldehyde	2.48E-04	none		0	2.48E-04	1
solid	3	acetaldehyde	na	1% BIF-NA[2]			1.03%[2]	
waste		fusel oils	na	BIF-NA			na	
	6	ash	11171	TCLP				

1 NSPS for steam-generating units
2 BIF regulations allow maximum firing rate of 1% of total fuel requirements based on BTU or mass basis, whichever results in lower feed rate

Table ES-6 summarizes the PSD permitting requirements and APC for all the scenarios evaluated. Facility sizes of 1000 and 3000 dtpd are also shown.

The standards presented above are for new facilities, but there may be some benefit to co-locating with an already permitted combustor or gasifier. The primary benefit is that the siting process could be avoided; siting any type of facility that combusts MSW or its by-products can be problematic. In addition, an existing MSW combustor could benefit from the volume reduction offered by a biomass-to-ethanol facility, thereby greatly increasing the total amount of waste a plant could receive.

Existing emissions standards are more lenient for existing facilities, but the difference in the pollution control requirements and associated costs between existing and new facilities do not appear to be large enough to warrant using an existing facility solely based on APC costs.

Preliminary costs for acid gas and particulate control APC equipment (EPA 1987) and SNCR (Hurst and White 1986) are tabulated in Table ES-7. These costs are not for CFB boilers; very few data are available for APC equipment for CFB boilers.

Certain information can be ascertained from the limited cost data available. For example, waste disposal costs for Scenario B are estimated at $27 million/yr (at $50/ton for disposal). These costs seem prohibitive, considering no revenue would be created from electricity sales. There is no advantage to Scenario C in terms of APC costs. There is an advantage to the base case with agricultural residues because the limestone injection in the CFB would be significantly cheaper than the spray dryer costs for MSW combustors. However, without conducting a detailed life-cycle cost analysis of the entire system, including electricity sale revenues, a final cost comparison for the different scenarios cannot be made.

Siting Issues

Siting constraints may increase the time and cost of the siting process and, in some cases, even delay bringing a facility on line or prevent a facility from ever operating. The primary regulatory parameters that affect siting of a biomass-to-ethanol facility include attainment classification, state and local permit requirements, and NEPA determination. Both attainment classification and permitting affect siting because they determine the specific air quality standards a facility must meet and whether pollutant emissions must be offset. State and local permit requirements are highly variable and can be a factor in choosing a site. NEPA requirements for a biomass-to-ethanol facility could vary depending on who built the facility and where it was built. Whenever possible, an EIS should be avoided because it is the most common method for a community to hold up a project. Although an EIS may not be required for a project based on NEPA review, some cases have required them on political grounds.

Depending on the NEPA and regulatory permit requirements for a facility, the public may or may not have a formal participatory role included in the siting process. The degree of public participation in the regulatory review process can significantly affect the overall siting process. Siting case studies for energy facilities usually recommend bringing the public into the decision-making process at an early stage and working with the public as much as possible when public opposition is perceived to be an issue (NREL 1993). Unfortunately, the public response is not always rational, and the not-in-my-backyard-syndrome sentiment can create momentum during the course of public participation in the review of a project.

MSW biomass-to-ethanol facilities have a number of siting issues on their side compared to MSW waste-to-energy facilities. Most importantly, an MSW biomass-to-ethanol facility should not be regulated as an MSW incinerator; this classification should help, because the public has shown a deep skepticism toward any type of incinerator, especially those that combust MSW. A second favorable point is that biomass-to-ethanol facilities can be perceived as renewable energy facilities, and the public has been favorable to renewable energy from an environmental standpoint. This is especially important because environmentalists have traditionally been the strongest opponents of waste-to-energy facilities.

The scenarios and feedstocks analyzed in this report could be perceived differently by the public. Some potential perceptions are listed in Table ES-8.

Table ES-6. APC and PSD Permitting Summary

Configuration/Feedstock/Size	PSD Required	Pollutants More Than 250 tpy	APC Assumed
Base Case (MSW, 1000 tpy)	No	--	SNCR, SD/FF
2000 tpd	Yes	NO_x, CO	SNCR, SD/FF
3000 tpd	Yes	NO_x, CO	SNCR, SD/FF
Scenario B (MSW, all sizes)	No	--	--
Scenario C (MSW, 1000 tpd)	Yes	SO_2	SNCR, SD/FF
2000 tpd	Yes	NO_x, CO, SO_2	SNCR, SD/FF
3000 tpd	Yes	NO_x, CO, SO_2	SNCR, SD/FF
Scenario D - MSW - 1000 TPD	No	--	SNCR, DI/FF
2000 tpd	No	--	SNCR, DI/FF
3000 tpd	Yes	Combined NO_x	SNCR, DI/FF
Base Case (Agricultural Residue 1000 tpd)	No	--	Limestone injection/FF
2000 tpd	Yes	NO_x, CO	Limestone injection/FF
3000 tpd	Yes	NO_x, CO, SO_2	Limestone inj/FF

Table ES-7. Preliminary Air Pollution Control Equipment Costs (1990 $)

APC Equipment	Capital Cost ($MM)	Annualized Cost ($MM)
Spray Dryer/Baghouse (1000 tpd @ 0.01 gr/dscf)	10.6	3.0
Spray Dryer/Baghouse (3000 tpd @ 0.01 gr/dscf)	26.1	7.7
Selective Noncatalytic Reduction	.08	.05

Table ES-8. Potential Public Perceptions Associated with Various Scenarios

Scenario	Preliminary Comments on Siting and Public Opposition
Base Case—MSW	EPA regulatory classification is an industrial process, not an MSW incinerator. Perception as a hazardous waste incinerator (caused by acetaldehyde combustion and BIF regulations) should be avoided.
Scenario B—MSW	Because there are very few emissions from this process, public opposition and siting should not be a problem.
Scenario C—MSW	Same as base-case MSW.
Scenario D—MSW	This process could be perceived as a clean way of disposing of MSW, as it would not be regulated as a combustor. Furthermore, it would have lower emissions than the base case, and for some plant sizes would not trigger a PSD permit.
Base Case—Agricultural Residues	Public opposition would be the least for this scenario because wood waste (and hence agricultural residues) are usually perceived as clean and renewable compared to MSW.

Introduction

This report analyzes the environmental regulatory requirements of various biomass-to-ethanol facilities and their effects on facility design (e.g., air pollution control [APC] equipment systems) and siting. Two feedstocks—municipal solid waste (MSW) and agricultural residues—are considered in this analysis. A base-case scenario that includes a fermentation system and a fluidized bed boiler is evaluated for both feedstocks, and three alternative biomass-to-ethanol systems are evaluated for the MSW feedstock to determine whether they would reduce costs or facilitate siting compared to the base-case scenario.

The biomass-to-ethanol processes evaluated in this report would have to meet environmental standards for air, solid waste, and liquid emissions. In most scenarios, these standards were promulgated by the U.S. Environmental Protection Agency (EPA) and are enforced by state environmental agencies, although many states have passed their own regulations. The environmental regulations discussed in this report are hundreds of pages long and very complex; furthermore, states may interpret and enforce them differently. The environmental regulatory analysis presented here focuses only on the main regulations that may significantly affect costs and siting of the biomass-to-ethanol facilities analyzed. Because environmental regulations are continually changing (usually becoming stricter), this analysis seeks to characterize regulations for the year 2000, about the time biomass-to-ethanol facilities could be commercialized.

This report provides a necessary environmental review for specific biomass-to-ethanol facilities. The regulatory analysis and cost and siting issues discussed in this report are very general and not intended for actual use in a permit application or an engineering feasibility study. Instead, the goal is to provide an environmental review that can be used to identify major environmental barriers that could affect the commercialization of biomass-to-ethanol facilities, and where appropriate, to evaluate cost effects of environmental requirements and regulations.

Overview of Systems Analyzed

Background

A description of the overall biomass-to-ethanol process is presented in this section. The primary source for the process design and performance parameters is the report, *Fuel Cycle Evaluations of Biomass-Ethanol and Reformulated Gasoline* (NREL 1992), which projects the state of the technology to the year 2000. Following the basic process description, several configurations are described. The environmental analysis will be conducted for these configurations.

Figure 1 presents the overall conceptual process configuration. The first stage is receiving and storing feedstock. MSW is already shredded and bundled; agricultural residues are received as round bales. The MSW or residues are stacked with front-end loaders in the covered storage are that is sized to hold 1–2 days of feedstock. The front-end loaders then take the bales to the debaling area. After debaling, the feedstock falls onto a belt conveyor that carries it to the mill.

During milling, the feedstock is reduced to a maximum particle size of about 3 mm. The milled feedstock is then sent to a prehydrolysis reactor and treated with dilute sulfuric acid at 320°F for 10 minutes to hydrolyze 90% of the hemicellulose into its component sugars (xylose, arabinose, galactose, and mannose); the remaining 10% is degraded to furfural. About 3% of the cellulose is also hydrolyzed to glucose. Another 0.1% of the cellulose is converted to hydroxy methyl furfural (HMF).

The prehydrolysis reactor effluent is flash cooled, and the resulting vapor (primarily furfural) is sent to the distillation section to preheat the dilute ethanol stream. Recycled process water is added to the liquid hydrolyzate to obtain a pumpable slurry of about 12 wt % solids. The slurry is then neutralized with lime to form gypsum (soluble and insoluble) that will be carried along in the process. After being neutralized, most of the slurry is sent to pentose fermentation, and a small fraction to cellulase production.

In pentose fermentation, a genetically engineered *Escherichia coli* converts 95% of the pentose to ethanol and carbon dioxide (CO_2) by the following reaction:

$$3\ C_5H_{10}O_5 \rightarrow 5\ C_2H_5OH + 5\ CO_2$$

The CO_2 entrains small amounts of water, ethanol, and other organic components into the off-gas. More than 99.5% of the ethanol and organics will be recovered by water scrubbing.

The hydrolyzate sent to cellulase production is used to grow the fungus *Trichoderma reesei*, which then produces cellulase. Nutrients and corn steep liquor are mixed and sterilized in a separate tank and added to the cellulase fermentors. After the 2-day batch fermentation is complete, the broth is pumped to the cellulase hold tank where it is pumped continuously to the cellulose fermentation process.

Cellulose is converted using the simultaneous saccharification and fermentation (SSF) process, during which the cellulase enzyme catalyzes the hydrolysis of cellulose to glucose that is then converted to ethanol by the yeast, *Saccharomyces cerevisiae*. The current design assumes 90% of the cellulose is converted to ethanol during the 3-day fermentation by the following reactions:

$$(C_6H_{10}O_5)_n + n\ H_2O \rightarrow n\ C_6H_{12}O_6$$

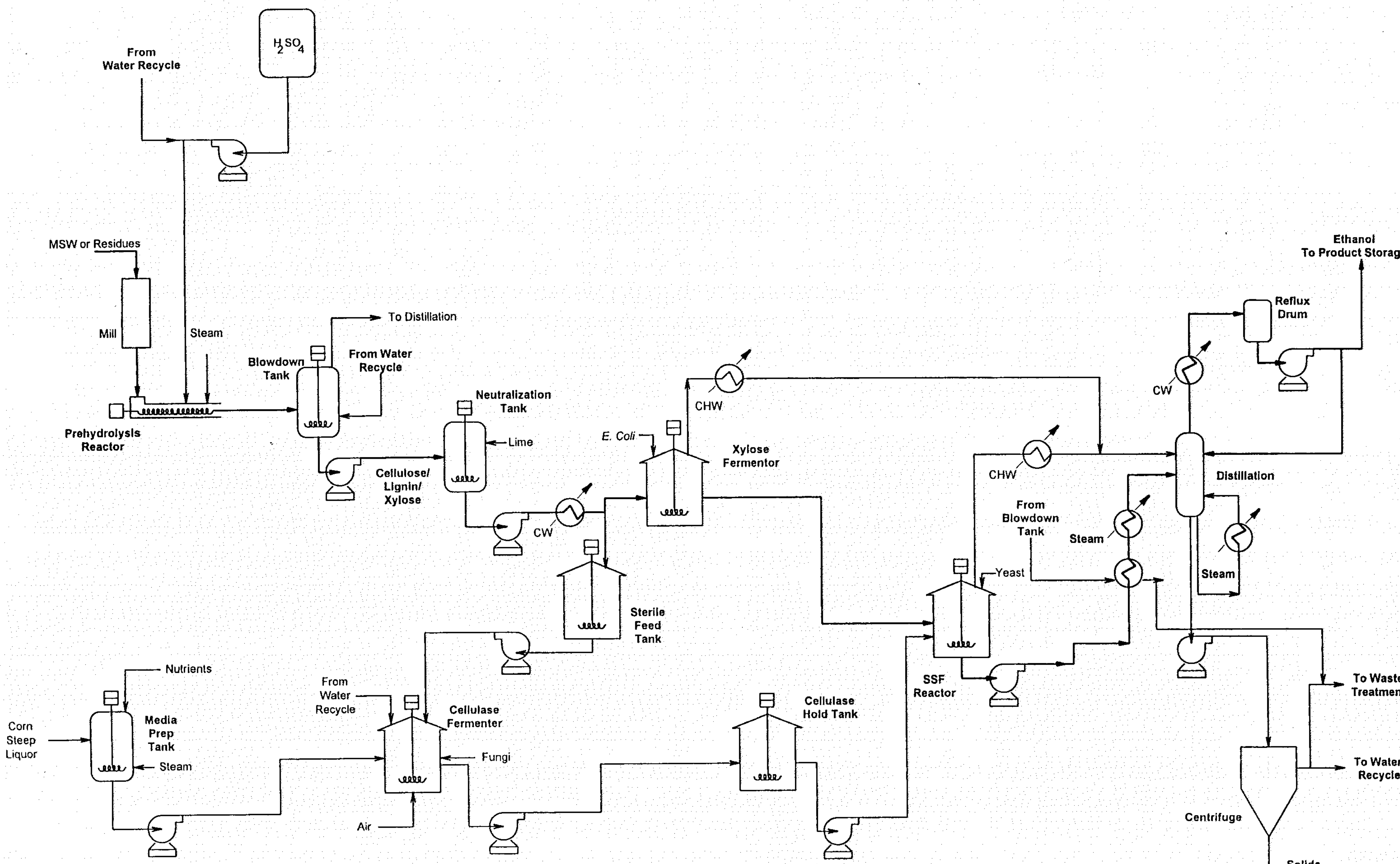
(Saccharification)

$$C_6H_{12}O_6 \rightarrow 2\ C_2H_5OH + 2\ CO_2$$

(Fermentation)

By-products such as fusel oils, acetaldehyde, and glycerol are also produced. About 0.1% of the inlet cellulose is converted to fusel oils (chiefly propyl alcohols). Acetaldehyde and glycerol are produced from 4.9% of the substrate, and yeast cells are produced from the remaining 5%. As with pentose fermentation, the off-gases contain CO_2, ethanol, water, and trace organics. Because of ethanol's inhibitory effects on the yeast, process water is added to the fermentors to maintain an ethanol concentration of less than 4.5%.

Figure 1. Biomass-to-ethanol process concept



The dilute ethanol stream from the SSF reactors is sent to ethanol purification, where distillation and molecular sieve dehydration produces anhydrous ethanol. The two columns recover 99.9% of the inlet ethanol. The first (beer) column concentrates the ethanol to about 40 wt %; the rectification column further concentrates it to near the azeotrope (95 wt %), and the molecular sieve system removes the rest of the water. The ethanol recovered from the fermentation off-gases is added to the rectification column. The bottoms from the beer column are sent to a centrifuge to remove the lignin and other solids. Sixty percent of the liquid stream from the centrifuge is returned to the process; the remainder is sent to waste treatment.

For a facility that processes 2000 dry tons per day (dtpd) of MSW, about 69.3 million gallons/year of anhydrous (99.9%) ethanol is produced. The same size facility that processes agricultural residues produces 78.9 million gallons. The ethanol production rate is directly proportional to feed rate; thus, at 1000 dtpd of MSW, the ethanol production rate is 34.7 million gallons/year and at 3000 dtpd, the rate is 104 million gallons/year.

Scenarios Analyzed

An analysis of the environmental factors that affect four configurations of the basic process was conducted. For Scenarios B–D, only MSW is considered because an MSW facility would likely be the most difficult to permit and site. If Scenarios B–D do not offer advantages to the environmental permitting and siting of an MSW biomass-to-ethanol facility, they would probably not offer advantages to a facility that uses agricultural residues, because MSW facilities are usually much harder to permit and site.

The four processes are described below. The configurations differ mainly in their treatment of solid and liquid effluents. The environmental regulations and siting requirements are analyzed in later sections of this report.

Scenario A—Base Case

Scenario A is shown in Figure 2. The unreacted solids recovered in the centrifuge following the beer still are combusted in a fluidized bed boiler. The liquid solvents (fusel oils and acetaldehyde) recovered during fermentation are also combusted in the boiler. The liquid effluent from the centrifuge is sent to wastewater treatment, which is composed of anaerobic digestion (AD) followed by aerobic treatment.

In AD, many organic components are converted to methane and CO_2; components that contain sulfate are converted to hydrogen sulfide (H_2S). Conversion factors have been developed for these gases based on the chemical oxygen demand (COD) and sulfate concentration of the wastewater (CH2M Hill 1991). Methane is produced at 0.241 lb/lb COD, and CO_2 is produced at 0.161 lb/lb COD; H_2S is produced at 0.252 lb/lb sulfate. The gas produced in AD is also sent to the fluidized bed boiler.

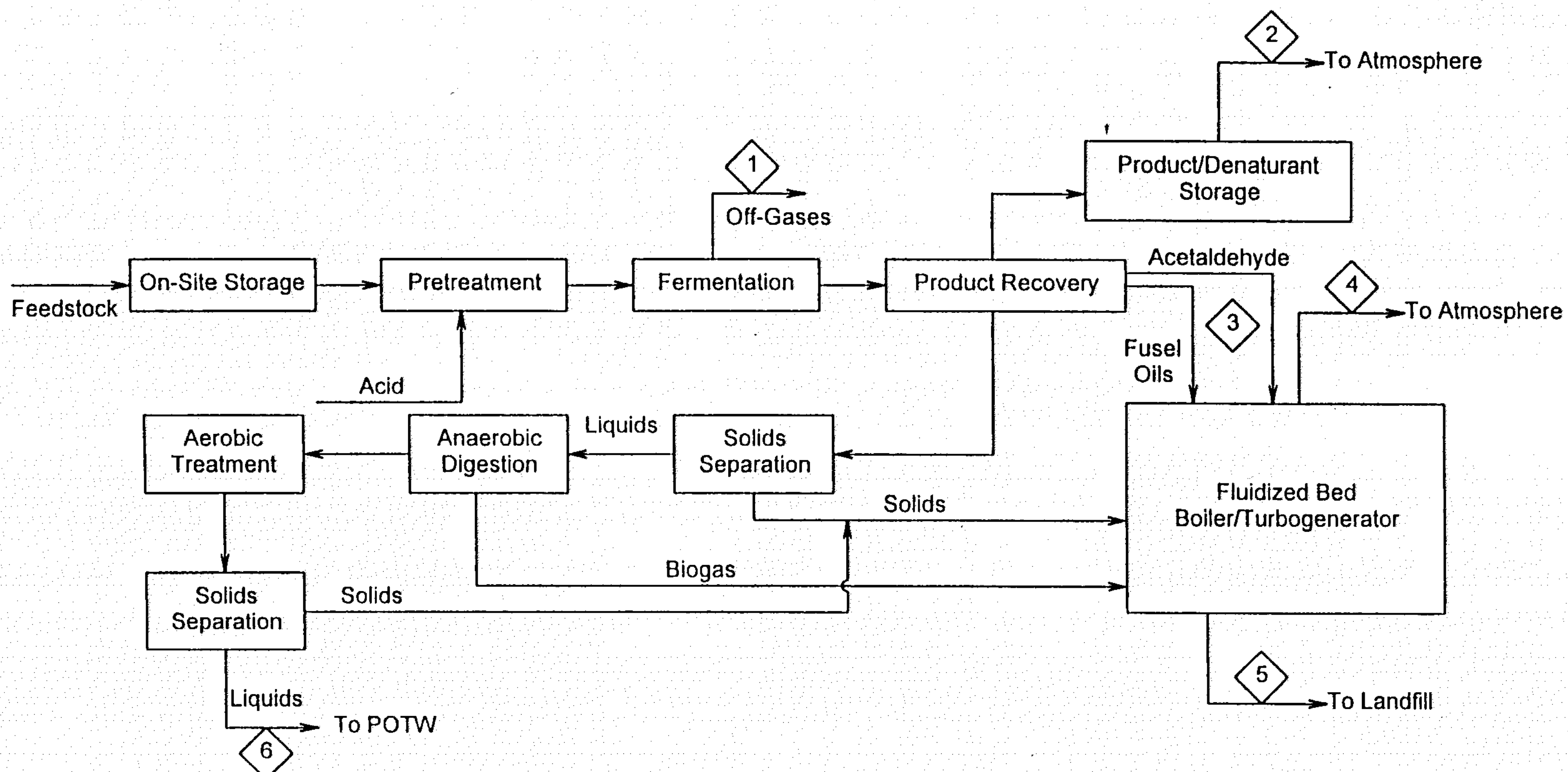
In aerobic treatment, the water is treated with air and the organic components are degraded to CO_2; about 0.252 lb of CO_2/lb COD is produced during aerobic treatment. The gases are emitted to the atmosphere following treatment in caustic and acid scrubbers and a carbon adsorption bed.

The final stage is clarification. The clarified liquid effluent is released from the facility to a publicly owned treatment works (POTW). The solids from the clarifier are concentrated by a belt filter press and sent to the fluidized bed boiler.

The acetaldehyde and fusel oils produced during fermentation are recovered during distillation. Both solvents are combusted in the boiler. For the process that uses MSW, more than 1100 lb/h of acetaldehyde and 95 lb/h of fusel oils are combusted in the boiler. With an agricultural residue feedstock, only 839 lb/h of acetaldehyde and 71 lb/h of fusel oils are produced and combusted.

Before being combusted in the boiler, the solid streams are dried to 65 wt % in a fluidized bed dryer using the flue gases from the boiler. Any solids entrained are captured in the dryer's baghouse. The fluidized bed boiler is coupled with a turbo generator to supply all the steam and electricity for the conversion process; excess electricity is sold to the grid. The boiler for the base-case configuration has a heat

Figure 2. Block flow diagram for Scenario A—base case



input of 579.4 MMBtu/h for MSW and 625.4 MMBtu/h for agricultural residues.

Scenario B—Eliminating the Boiler

Scenario B is very similar to the base case except that the boiler is eliminated; steam and electricity are purchased. All wastes and by-products that went to the boiler in the base case must now be treated or disposed, or both. Because the AD produces significant quantities of methane, the facility would probably not have this unit operation; only aerobic treatment would be used. Solid wastes would be landfilled or sent to an MWC off-site. Acetaldehyde would be sent for disposal, and fusel oils would be added to the ethanol product. This scenario demonstrates the benefits of not being classified as a waste-to-energy facility. Figure 3 shows a block flow diagram for this scenario.

Scenario C—Anaerobic Digestion of All Wastes

Scenario C, shown in Figure 4, has the boiler and AD like the base case. The major change is that the solids are not separated before AD. All waste process solids and liquids are sent to the digester, and the biogas from the reactor is combusted in the fluidized bed boiler. Following aerobic treatment, the solids are dewatered and combusted in the boiler. The principal advantages are that the boiler is simplified and lower emissions are expected. Because much of the fuel will now be gaseous, solid handling problems and the high particulate matter (PM) emissions associated with solids combustion will be reduced.

Scenario D—Gasifying All Wastes

As shown in Figure 5, Case D incorporates a gasification system. The solids from the beer still are separated from the liquids and sent to a biomass gasifier. For this analysis, an indirect gasifier, similar to that under development at Battelle-Columbus Laboratory, is considered. The gasifier produces a medium-Btu gas with a heat content of about 350 Btu/dscf. The liquids from the beer still are sent to wastewater treatment (AD and aerobic treatment) as in Scenarios A and C. Gas produced in the gasifier is combined with that from AD and combusted in a gas turbine followed by a waste heat recovery boiler and a steam turbine. This system supplies all the facility's electricity and steam. The gas turbine has a heat input of 337 MMBtu/h (lower heating value); this is similar in size to a GE LM-5000 turbine. The combustor that heats the gasifier has a heat input of 66 MM Btu/h. This scenario may have the lowest emissions of all. Gasification and AD clean the fuel by converting the solids to gases.

Figure 3. Block flow diagram for Scenario B—elimination of boiler

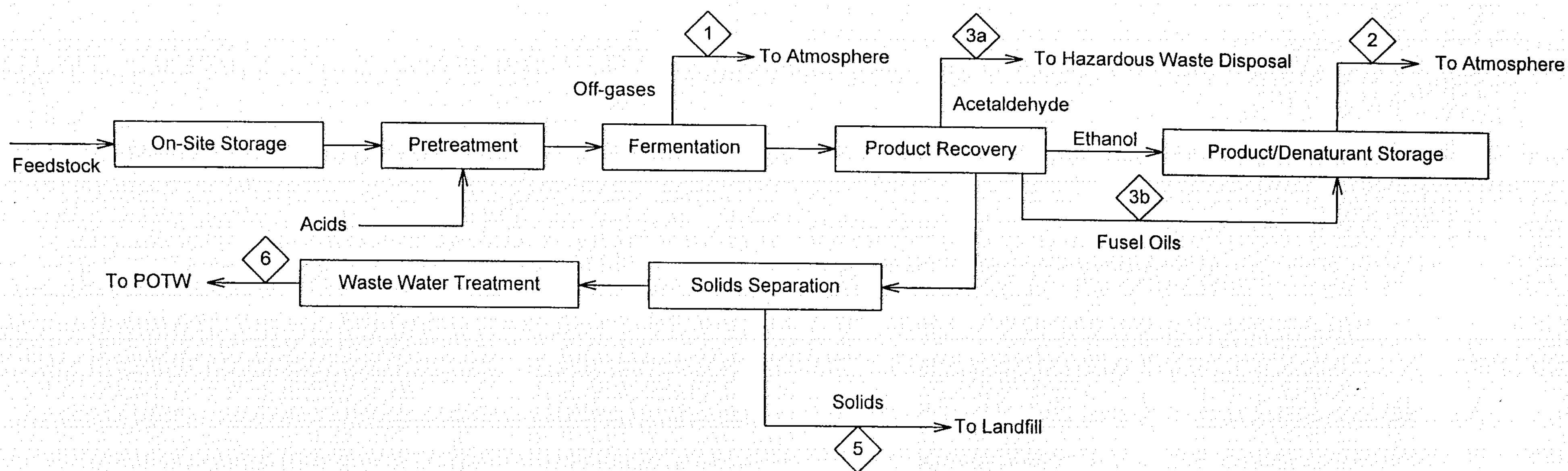


Figure 4. Block flow diagram for Scenario C—Anaerobic digestion of all wastes

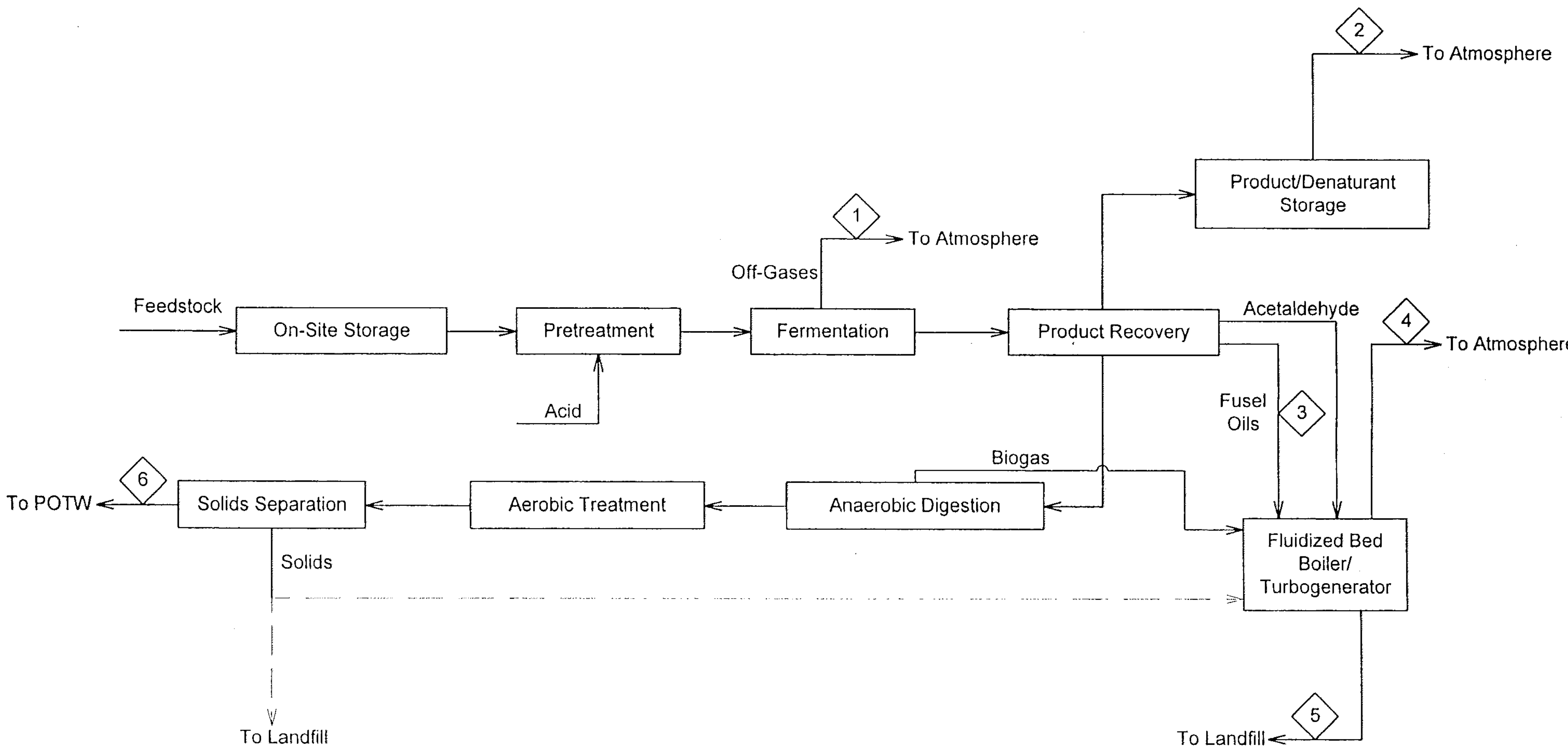
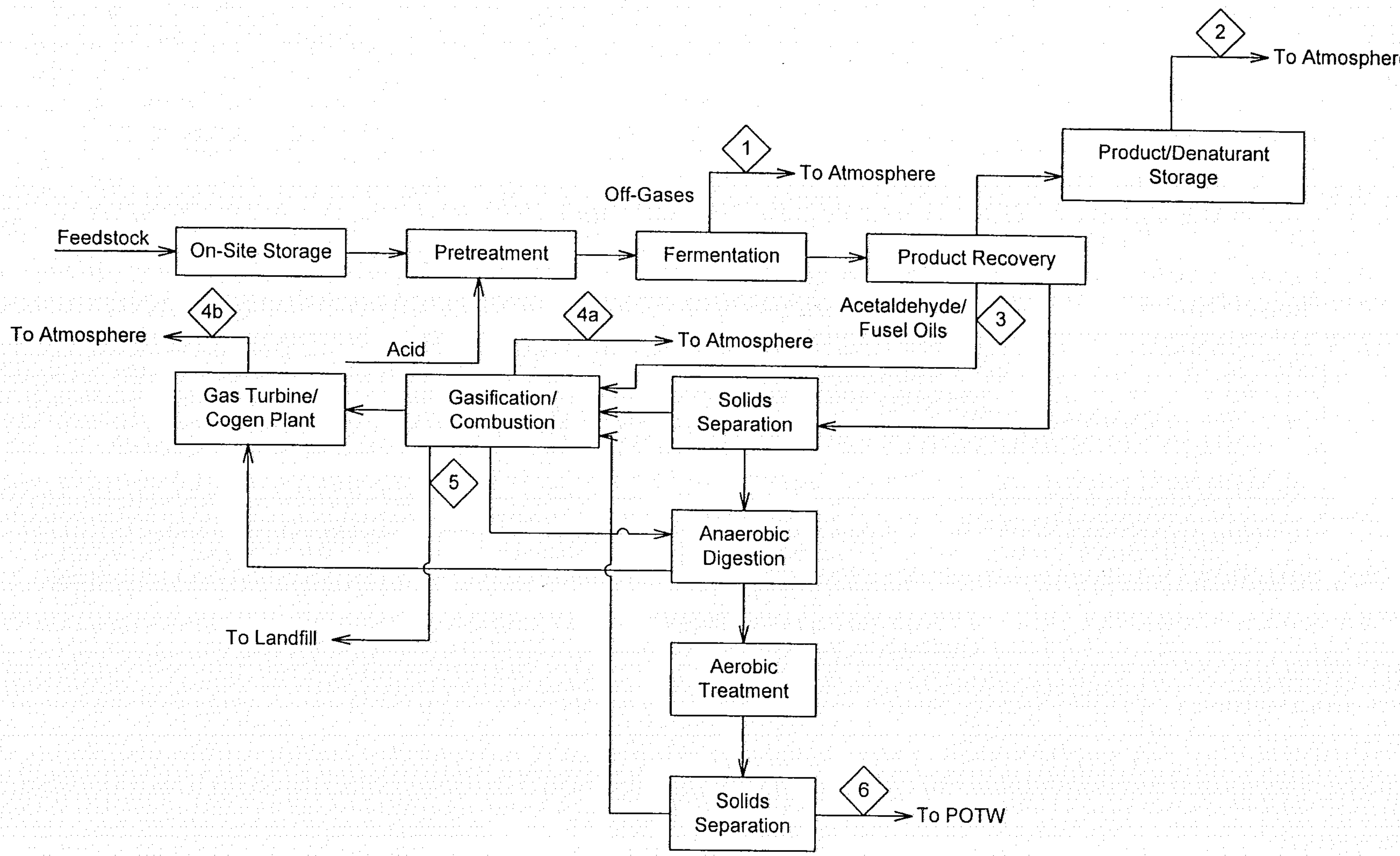


Figure 5. Block flow diagram for Scenario D—Gasifying all wastes



Regulatory Analysis

Background

This analysis focuses on the existing and projected environmental regulations that govern the biomass-to-ethanol facilities described in the Overview. This report emphasizes the regulations for the base-case scenario for MSW and agricultural residue feedstocks because this design will likely be the first commercialized; however, regulations that affect the other scenarios are also presented. Based on a thorough understanding of the environmental regulations, pollution control equipment and siting issues are discussed later.

Federal regulations are emphasized in this analysis, not because they are the strictest or most pre-eminent, but for simplicity. State laws are too varied to be covered in depth; they are discussed primarily when they are more stringent than the corresponding federal regulations.

This section does not exhaustively review all environmental regulations that could affect the biomass-to-ethanol facilities under consideration; rather, it reviews the existing regulations that are projected to have the greatest effect on plant design, permitting, and cost, and projects future regulations.

Air Regulations

Of the three sets of environmental regulations—air, solid waste, and water—air will usually have the greatest regulatory impact on permitting and siting biomass-to-ethanol facilities. The Clean Air Act Amendments of 1990 (CAAA-90) are the primary federal laws that affect air quality requirements for biomass-to-ethanol facilities. The EPA has been developing regulations to implement CAAA-90 and will continue to do so for many years. Hence, in addition to existing EPA regulations that affect biomass-to-ethanol facilities, the requirements for future regulatory development as stipulated in CAAA-90 indicate the air quality areas perceived as most important. This information, along with recent regulatory developments within EPA and among the various states, can be used to project regulatory trends. Future EPA studies mandated under CAAA-90 that could affect air permitting for biomass-to-ethanol facilities are shown in the Appendix.

Standards for specific pollutants are presented in this section because they are the driving force for many design requirements, such as APC equipment, that can significantly affect costs for a plant. Pollutant standards can also affect the public's perception of health effects. For example, if dioxin standards do not apply to a plant, the public is often less likely to associate public health risks from dioxins with that specific facility. Regulations that monitor pollutants, including stack test requirements, are also presented where applicable because of their potential effect on plant costs. Although a detailed analysis of APC equipment for specific plant types and sizes is presented in the Analysis of Environmental Permitting and Pollution Control Equipment section, APC equipment is discussed in this section as it pertains to regulatory developments.

All fluidized bed combustors (FBCs) considered for the various biomass-to-ethanol boiler systems will meet state-of-the-art operating requirements as stipulated by EPA. Except for carbon monoxide (CO) standards used to indicate combustion efficiency, EPA requirements for temperature control and boiler operation, as well as waste loading and operator training requirements, are not analyzed in this report.

Ambient Air Quality

Attainment areas are regions that meet national ambient air quality standards (NAAQS) for the six criteria pollutants: tropospheric ozone (O_3), CO, particulate matter (PM), sulfur dioxide (SO_2), nitrogen dioxide, (NO_2), and lead. Table 1 shows the NAAQS. To receive a permit for a facility, the proposed facilities—both alone and in conjunction with all other facilities in the area—must show that the NAAQS will not be exceeded. Air quality dispersion models are used to model the stack emissions from a plant to ensure the NAAQS are not violated.

Table 1. National Ambient Air Quality Standards

Pollutant	Federal ($\mu g/m^3$)
O_3	
1-h average	235
CO	
1-h average	40,000
8-h average	10,000
NO_2	
Annual average	100
SO_2	
3-h average	1,300
24-h average	365
Annual average	80
Suspended PM-10[1]	
24-h average	150
Annual average	50

[1] PM less than 10 μ in diameter (inhalable)

The EPA has promulgated Prevention of Significant Deterioration (PSD) requirements for permitting plants in attainment areas. PSD reviews are required for new or modified projects in attainment areas for the pollutants previously mentioned. PSD review requirements include the following (ENSR 1988):

- Evaluate alternative pollution control systems and techniques and demonstrate that best available control technology (BACT) will be applied to the new source
- Analyze existing ambient air quality in the vicinity of the new source
- Demonstrate, usually through air quality dispersion analysis, that the emissions from the new source and from nearby sources will not exceed NAAQS or PSD thresholds
- Evaluate the source's impact on soils and vegetation
- Analyze the air quality impacts associated with direct growth created by the new source
- Assess the source's impact on visibility.

In general, BACT represents the maximum, economically feasible, level of control for specific pollutants. BACT must at least ensure that the NAAQS are not violated and that any applicable New Source Performance Standards (NSPS) are met. In addition, many states have separate BACT reviews that are significantly more stringent than federal BACT requirements. Thus, BACT review may be required for emission levels below the PSD threshold limits. Biomass-to-ethanol facilities with annual emissions above the thresholds shown in Table 2 are considered major sources and are subject to federal PSD permit requirements.

Table 2. EPA Threshold Limits for Major Sources Subject to PSD Review

Pollutant	Emission Rate (tons/year)
CO	250
Reactive organic gases	250
NO_x	250
SO_2	250
PM-10	250

Nonattainment areas do not meet NAAQS for a specific pollutant. Under CAAA-90, regions will be stratified by the degree of nonattainment, and various nonattainment areas may be regulated differently. This could significantly affect site locations of new or retrofit biomass facilities, and new facilities would, in many cases, be required to obtain more than equal reductions in nonattainment pollutants from other sources in the area. Many areas in the United States are not in attainment for O_3; hence, the O_3 standard would probably be the most difficult to meet. Current O_3 attainment strategies, as enforced by state implementation plans (SIPs), seek to comply with O_3 standards by reducing volatile organic compounds (VOCs) and NO_x, which are both O_3 precursors. The degree of regulation for a specific plant is determined partly by the severity of O_3 nonattainment of its location.

Recent EPA guidance requires that major sources of NO_x and VOCs in O_3 nonattainment or transport areas (Maine to Virginia) install reasonably available control technology (RACT), defined as a control technology recognized to be technically and economically achievable for most existing sources (ENSR 1988). EPA's expected RACT standard for electric utilities is shown in Table 3. The Northeast States Coordinated for Air Use Management (NESCAUM) has proposed standards in two phases, shown in Table 4.

New major sources in O_3 nonattainment or transport areas must reduce emissions from other sources to offset any increase in NO_x emissions and install controls to meet lowest achievable emissions rates (LAER). Depending on the degree of nonattainment, emission offsets vary from one-to-one to more stringent reductions such as two-to-one. The controls (RACT, BACT, LAER) required are pollutant specific, so an O_3 nonattainment area may require LAER for NO_x but only BACT for PM-10. PM-10 nonattainment areas are less common than O_3 nonattainment areas, but are still found in many urban regions in the United States. Los Angeles is the only nonattainment area for NO_x.

In general, siting a facility in a nonattainment area can introduce much more stringent permitting requirements. Unfortunately, many urban areas in the United States, especially in the Northeast and in California, are not in attainment for O_3.

Table 3. EPA's Expected NO_x RACT, lb/MMBtu (30-day average)

Fuel	Tangential	Wall	Cyclone	Stokers
Gas/Oil	0.2	0.3	0.55	0.55
Coal/Wet Bottom	N/A	0.7	0.7	N/A
Coal/Dry Bottom	0.45	0.5	N/A	0.7

Table 4. NESCAUM Recommended NO_x RACT

Fuel	Tangential	Wall	Cyclone	Stokers
Gas only	0.20	0.20	N/A	N/A
Gas/Oil	0.25	0.25	0.43	N/A
Coal/Wet Bottom	1.00	1.00	0.55	N/A
Coal/Dry Bottom	0.38	0.43	N/A	0.32[2]

[1] Based on 24-h average for coal-fired boilers and 1-h average for gas/oil-fired boilers.

[2] For stokers that use 25% or more solid fuels other than coal (e.g., wood or tires), the recommended limit is 0.33 lb/MMBtu.

Interim Phase II NO_x Limit

Oil/Gas	0.1 lb/MMBtu (1-h average)
Coal	0.21 lb/MMBtu (24-h average)

Hazardous Air Pollutants

Hazardous air pollutants (HAPs) are regulated under Title III of CAAA-90, which contains a list of 189 substances EPA will review to determine applicable standards. The regulations for air toxics will not attempt to control according to pollutant, but by industry type. Under this title, "major sources" are stationary sources that emit 10 tons/year of any listed HAP or 25 tons/year of all HAPs combined. These thresholds are not standards; they are merely used to classify sources for regulation.

Commercial and industrial plants identified as major sources will be listed by category and subcategory, with control levels prescribed for each category. The EPA has published a preliminary list of major sources. Electric utility steam-generating units are listed as a major source, but EPA has postponed regulation for HAPs until a special study is completed. Other major source categories that could affect biomass-to-ethanol facilities are industrial boilers and stationary turbines. Technology-based standards under Title III will rely on maximum achievable control technology (MACT), defined as the emission control achieved by the best-performing 12% of existing sources.

Many HAP emissions for MWCs, such as toxic metals (e.g., cadmium), will be regulated under NSPS—included under Title I of CAAA-90—and by state toxics regulations. HAPs of concern for FBCs of post-fermentation agricultural residues include acetaldehyde, formaldehyde, and polycyclic aromatic hydrocarbons (PAHs).

In addition to the ambient air quality and HAP standards, specific regulations exist for various plant and feedstock types.

Federal MWC Regulations

The definition of MSW (Subpart Ea, 40 CFR 60.50a) reads as follows:

> MSW means household, commercial/retail, and/or institutional waste . . . Household, commercial/retail, and institutional waste do not include sewage, wood pallets, construction and demolition wastes, industrial processes or manufacturing wastes, or motor vehicles.

Based on the above definition, nonreacted solids from a biomass-to-ethanol facility would not be considered MSW, because they are wastes from an industrial/manufacturing process; hence, MSW biomass-to-ethanol facilities would not have to meet standards for MWCs. This is an extremely important regulatory classification, because it allows MSW biomass-to-ethanol facilities to be excluded from MSW regulations. More importantly, it would help MSW biomass-to-ethanol plants to not be perceived as a waste-to-energy facilities by the public.

State agencies could argue that an MSW biomass-to-ethanol facility should fall under the MWC regulations, but there is no federal mandate for this. States would therefore have to change their MSW definitions to regulate an MSW biomass-to-ethanol facility as an MWC. However, during the BACT review of the PSD permitting process, states could require the same or similar BACT requirements for an MSW biomass-to-ethanol plant as they would for an MWC. Regulations for MWCs are discussed in detail because an MSW biomass-to-ethanol plant would be conservatively assumed to meet the MWC regulatory requirements, even though it would not fall under this regulatory classification. (Meeting the MWC standards would be a good approach to working with a state environmental agency during the PSD permitting, because it would demonstrate prudent emissions control for a completely new type of permit, a PSD permit for a biomass-to-ethanol facility.)

MWC regulations are specified according to the facility construction date and size. In general, the regulations are more stringent with larger and newer facilities.

Existing MWC Regulations

Emissions guidelines for standards and monitoring requirements for MWCs constructed on or before December 20, 1989 are shown in Tables 5 and 6 (40 CFR Part C). State regulatory agencies use these guidelines to develop their own regulations; however, in most cases, the states will adopt them as standards, and this analysis assumes they are actual standards.

Also shown in Table 5 is the type of APC equipment used to develop the standard. The EPA used the costs for the type of APC equipment shown to estimate the cost and benefits of controlling pollutant emissions. Based on EPA's estimates, the APC equipment listed should, if properly designed, be able to control pollutant emissions to the corresponding standards.

MSW combustion standards are important to evaluate in this analysis because a new biomass-to-ethanol facility might "piggy-back" on an MSW facility and burn wastes in a combustor that has already been permitted. Therefore, it is important to compare standards for existing facilities to new facilities to evaluate any potential benefits in terms of environmental permitting, public perception, and APC equipment costs. As shown in Tabled 5 and 6, these regulations exclude MSW plants with a capacity of less than 225 Mg/day (250 tons/day).

Table 5. Emission Regulations for Existing Fluidized Bed MWCs Constructed Before December 20, 1989[1]

Pollutant	Very Large MSW Plants (> 1000 Mg/d or 1,100 ton/d)	Large MSW Plants (> 225Mg/d or 250 ton/d)	Type of APC Equipment Used as Basis for Standard
CO (for FBC)	100 ppmvd 4-h average)	100 ppmvd (4-h average)	GCP[2]
Organic emissions (measured as total dioxin/ furans)	60 ng/dscm	125 ng/dscm	GCP, spray dryer, and ESP[3] for very large plants; GCP, dry sorbent injection, and ESP for large plants
Metal emissions (measured as PM-10)	34 mg/dscm	69 mg/dscm	ESP
SO_2	30 ppmvd or 70% reduction (24-h average)	30 ppmvd or 50% reduction (24-h average)	Spray dryer and ESP for very large plants; dry sorbent injection and ESP for large plants
HCl	25 ppmv or 90% reduction	25 ppmv or 50% reduction	Same as SO_2
Opacity	10% (6-min average)	10% (6-min average)	ESP

1 All emission levels are at 7% O_2, dry basis. There are no standards for units less than 225 Mg/day.
2 Good combustion practice
3 Electrostatic precipitator

Table 6. Monitoring Requirements for Existing Fluidized Bed MCWs

Pollutant	Very Large MSW Plants (> 1000 Mg/d or 1100 ton/d)	Large MSW Plants (> 225Mg/d or 250 ton/d)
CO	CEMS[2] (4- or 24-h average)	CEMS (4- or 24-h average)
SO_2	CEMS (24-h geometric mean)	CEMS (24-h geometric mean)
PM-10, dioxins/furans[1] and HCl	Annual stack test	Annual stack test
Opacity	CEMS (6-min average)	CEMS (6-min average)

1 Measured as total tetra-through-octa chlorinated dibenzo-p-dioxans and dibenzofurans, not as toxic equivalents.
2 Continuous Emission Monitoring System

MWC Regulations for New Plants

On December 20, 1989, EPA proposed NSPS for new MWCs (40 CFR Part 60 Subpart Ea). Although the regulations were promulgated in 1991, EPA recently determined that they were not fully consistent with the requirements of Section 129 of CAAA-90. Thus, EPA developed new NSPS for MWCs in Subpart Eb that will comply with the requirements of Section 129. These regulations will apply to MWCs that were constructed, modified, or reconstructed after September 20, 1994 and will go into effect in October 1995. The Subpart Ea regulations cover facilities constructed, modified, or reconstructed after December 20, 1989 and on or before September 20, 1994.

Tables 7 and 8 outline the regulations for Subparts Ea and Eb. In both cases, facilities that process more than 225 Mg/day of MSW are classified as large, and those that process more than 35 Mg/day but less than 225 Mg/day are classified as small. Thus, not only do the regulations become more stringent with time, but smaller facilities are now subject to regulation.

The MSW NSPS for new plants are stricter than the guidelines for existing MSW plants, but the pollution control equipment is similar: for the existing guidelines, DSI followed by PM collection in a baghouse or ESP will generally suffice, but for a new MSW plant a spray dryer followed by a baghouse (or ESP) would be adequate. A DSI is cheaper than a spray dryer system, but its cost alone would not justify using an existing permitted MSW plant to combust post-fermentation MSW. The only exception to this is small MWCs. Before 1989, MWCs smaller than 225 Mg/day were not regulated. In addition, new small plants must, in general, meet the same requirements as new large plants, but small MWCs built just 5 years ago have less stringent regulations than large facilities built at the same time. Although APC costs will likely not be the determining factor in whether to collocate a facility, permitting and siting a new MSW plant can be very difficult. Siting issues alone could justify using an existing plant.

State Regulations for MWCs

State regulations for MWCs must be at least as stringent as federal standards. Most states do not have specific regulations (other than NSPS standards) for MWC stack emissions. However, many have air toxics programs that include standards for pollutants not regulated under NSPS. They usually apply to ambient concentrations at the ground level, rather than specifically limiting the amount exiting the stack. These standards are typical of regulations that have been developed based on health risk assessments. States with requirements for conducting a health risk analysis for toxic pollutants can make permitting more difficult, as very few people want their cancer risks calculated, even if they are low.

DePaul and Crowder (1989) studied the impact of various state air toxics programs on MWCs. Table 9 shows a summary of some of their findings. There are three categories; the standards in category 3 are significantly more stringent than those in category 1. Many states are waiting for EPA to set emission limits for HAPs under Title III of CAAA-90 and are therefore not currently promulgating their own regulations for metals such as cadmium.

Toxic air pollutant emissions that are of concern for state MWC permits include arsenic, beryllium, cadmium, chromium, nickel, dioxins, furans, and mercury. In many states, air quality dispersion modeling and a health risk assessment are required to show that risks from toxic pollutants are within acceptable levels. Even if BACT is installed, many states will not allow a permit for a facility unless the risks are shown to be within state requirements.

State regulations often contain standards for pollutants not contained in the NSPS, many of which are metals such as cadmium and chromium, which may be controlled with NSPS BACT for particulate and acid gas control (e.g., spray dryer with baghouse). However, temperatures upstream of the baghouse may have to be reduced more than would be required for only PM-10 control so metals can condense for removal in the baghouse.

Table 7. Emission Regulations for Large and Small MWCs Built between December 1989 and September 1994[1]

Pollutant	Standard	Type of APC Equipment Used as Basis for Standard
CO (Large and Small)	100 ppmvd (4-h average)	GCP
Organics[2] (Large) Organics (Small)	30 ng/dscm or 0.5 ng/dscm TEQ[3] 60 ng/dscm or 1.0 ng/dscm TEQ	GCP, SD/FF[4]/CI[5] GCP, DSI/ESP/CI
Metals[6] (Large) Metals (Small)	27 Mg/dscm 69 Mg/dscm	Same as organics Same as organics
Cadmium (Large) Cadmium (Small)	0.040 Mg/dscm 0.10 Mg/dscm	Same as organics Same as organics
Lead (Large) Lead (Small)	0.50 Mg/dscm 1.6 Mg/dscm	Same as organics Same as organics
Mercury (Large and Small)	0.080 Mg/dscm or 85% reduction	Same as organics
SO_2 (Large) SO_2 (Small)	35 ppmvd or 75% reduction (24-h average) 80 ppmvd or 50% reduction (24-h average)	Same as organics Same as organics
HCl (Large) HCl (Small)	35 ppmvd or 95% reduction (24-h average) 80 ppmvd or 50% reduction (24-h average)	Same as organics Same as organics
NO_x (Large) NO_x (Small)	180 ppmvd No standard	SNCR[7] No control required
Opacity (Large and Small)	10% (6-min average)	Same as organics

1 All emission levels are at 7% O_2, dry basis
2 Measured as dioxin/furan
3 Toxic equivalency
4 Fabric filter
5 Carbon injection
6 Measured as PM
7 Selective non-catalytic reduction

Table 8. NSPS for New MWC[1]

Pollutant	Standard	Type of APC Used as Basis for Standard
CO (Large and Small)	100 ppmvd (4-h average)	GCP
Organics (Large and Small)	13 ng/dscm or 0.20 ng/dscm TEQ	GCP, SD/FF/CI
Metals (Large and Small)	15 Mg/dscm	Same as organics
Cadmium (Large and Small)	0.010 Mg/dscm	Same as organics
Lead (Large and Small)	0.10 Mg/dscm	Same as organics
Mercury (Large and Small)	0.080 Mg/dscm or 85% reduction	Same as organics
SO_2 (Large and Small)	30 ppmvd or 80% reduction	Same as organics
HCl (Large and Small)	25 ppmvd or 95% reduction	Same as organics
NO_x Large Small	 180 ppmvd No control required	 SNCR NA
Opacity (Large and Small)	10% (6-min average)	Same as organics

1 All emission levels are at 7% O_2, dry basis.

Regulations for Gas Turbines

Gasification of the post-fermentation, nonreacted solids is included in Scenario 3. Regulations for new and existing integrated gasifier combined cycle plants are presented in Table 10 and would apply to the gas turbine in this scenario.

Federal Regulations for Existing Biomass-to-Ethanol Facilities That Use Agricultural Residues

Table 11 shows the regulatory requirements for existing steam-generating boilers, some regulations for biomass facilities in California and the Northeast States (which in many cases are stricter), and regulatory trends. These regulations would apply to biomass-to-ethanol facilities that use either MSW or agricultural residue feedstocks. However, NSPS for MWCs are more stringent and are used in later sections to determine the environmental requirements for systems that use MSW feedstocks.

All existing units located in O_3 nonattainment and transport areas will be subject to RACT limits. The EPA has issued and NESCAUM has proposed RACT guidelines for NO_x emissions in O_3 nonattainment and transport areas (see Tables 3 and 4), but they are specific to combustion technology and fuel type and do not include CFB boilers. Nevertheless, CFB boilers should be assumed to have met or exceeded these standards. There are also RACT PM-10 standards for existing facilities in nonattainment areas.

Table 9. Summary of State Air Toxics Programs as of 1989

State	Number of Non-Criteria Pollutants Regulated	Basis of Ambient Guideline	Control Technology Required	Type of Sources Covered
Category 1				
Alabama	None listed	None	No	New
Arkansas	None listed	None	No	New
Missouri	None listed	None	Yes	New
Washington	None listed	None	(Operational)	New
Category 2				
Connecticut	1000	RA[3]/OS[4]	(Operational)	All
Florida	Open[1]	RA/O	Yes	All
Georgia	Open	OS	No	New
Main	CDD[5]/CDF[6]	RA	No	New
Maryland	Open	RA/OS	Yes	All
Massachusetts	100a[2]	RA	No	All
Minnesota	CDD/CDFa	RA/OS	Yes	All
New Hampshire	Open	RA/OS	No	New
North Carolina	125	OS (proposed)	No	New
Ohio	29a	RA (proposed	No	New
Oklahoma	CDD/CDF	RA	No	New
Pennsylvania	99a	RA	Yes	New
Rhode Island	40a	RA	Yes	New
Texas	12	OS	No	All
Vermont	250	RA/OS	Yes	All
Virginia	650a	OS	Yes	New
Wisconsin	99a	RA/OS	Yes	New
Category 3				
	22	RA	Yes	New
California	11	RA/OS	Yes	New
New Jersey	252a	RA/OS	Yes	All
New York	Open	RA/OS	Yes	New
Michigan				

1 State designated (open-ended list of pollutants)
2 a—State can designate additional pollutants
3 Risk assessment
4 Occupational standards
5 Chlorodibenzo-p-dioxin
6 Chlorodibenzofuran

Source: DePaul and Crowder 1989

Table 10. Integrated Gasifier Combined Cycle Regulations

Pollutant	Federal Standard/ Regulatory Context for Existing Facilities	Federal Standard/ Regulatory Context for New Facilities	Comments
CO	RACT limits to be set	NSPS limits to be set; 250 tpy PSD threshold	
HC	RACT limits to be set	NSPS limits to be set; 250 tpy PSD threshold	
NO_x	RACT limit for coal boilers 0.45-0.70 lb/MMBt [1]	NSPS limit for combustion turbine 70[2] ppmv; 250 tpy PSD threshold	NESCAUM Phase II limits for coal boilers estimated at 0.21 lb/ MMBtu; California LAER at 9 ppmv
SO_2	CAAA-90 Phase 1 criteria 2.5 lb/MMBtu	NSPS limit for CT 150 ppmv; CAAA-90 limit 2.5 lb/MMBtu, 250 tpy PSD threshold	CAAA-90 Phase II at 1.2 lb/MMBtu in 2000
PM-10	No standards exist	250 tpy PSD threshold	
Metals	No current federal limits; emission limits to be set for major sources[3]	No current federal limits; emission limits to be set for major sources[3]	

1 For O_3 nonattainment or transport regions. This is a typical limit calculated from an equation given in CFR Part 60.332 using typical inputs (e.g., manufacturer's rated heat rate at rated load in kj/h).

2 Regulations will be set by year 2000 for major sources

As mandated under Title III of CAAA-90, any source that emits more than 10 tons/year of a HAP or more than 25 tons/year of a combination of HAPs, is subject to MACT for that pollutant. Acetaldehyde, formaldehyde, and PAHs are among the pollutants EPA defines as hazardous that could be subject to MACT. Industrial and commercial boilers, including those fired with wood, are source categories for HAPs and are scheduled to be regulated by November 15, 2000.

Under CAAA-90, SO_2 emissions from utilities and independent power producers may not exceed the number of SO_2 allowances held. Annual issued allowances will be equivalent to a nationwide average of 1.2 lb/MMBtu.

New Source Performance Standards for Agricultural Residue Biomass-to-Ethanol Facilities

Depending on the heat input capacity, a boiler fired by agricultural residues (or nonreacted MSW feedstocks) that generates steam would be subject to Standards of Performance for New Stationary Sources (40 CFR Part 60) for steam-generating units. Fossil-fueled and wood-burning new facilities that generate more than 100 MMBtu/h heat input capacity are subject to Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. Wood-fired facilities are not subject to Subpart Da—Standards of Performance for Electric Utility Steam Generating Units, as long as fossil fuel heat input (e.g., coal, oil, or natural gas co-fired with wood) does not exceed 250

MMBtu/h. Subparts E and Ea, which govern incinerators and MWCs, do not apply because agricultural residues do not meet the federal definition of a solid waste or MSW.

The NSPS requirements for steam-generating units in Subpart Db refer to specific fuel types, such as coal, oil, and wood waste. Agricultural residues are not specifically listed as a fuel type, so biomass-to-ethanol facilities that use agriculture residues would probably be required to meet only the general requirementsin Subpart Db, such as the general notification requirements and the reporting of fuel types, and not the emission limits listed for specific fuel types. However, most states would require some type of emission limits.

Table 11. Regulatory Limits for Existing Steam-Generating Facilities (29 MW and Higher)

		Comments	
Pollutant	**Federal Standard/ Regulatory Context**	**Sample State Standards (Regulation/State)**	**Regulatory Trends**
CO		0.14 lb/MMBtu (CA)[1]	RACT limits to be set
HC		0.24 lb/MMBtu (CA)[1]	RACT limits to be set
NO_x	0.6 lb/MMBtu (NSPS)[2]	0.30 lb/MMBtu (NESCAUM)[1] 0.080 lb/MMBtu (CA)[1]	
SO_2	2.5 lb/MMBtu (CAAA-90, Title IV, Phase II[3]; NSPS[2])	0.033 lb/MMBtu (CA)[1]	1.2 lb/MMBtu (CAAA-90, Title IV)[3]
PM-10	0.03 lb/MMBtu (NSPS)	0.045 lb/MMBtu (CA)[1]	RACT limits to be set
Metals	No current federal limits; emission limits to be set for major sources[4]		EPA study under way

1 Permit emission standard issued for biomass-fired FBC (Donovan and Associates 1992).
2 Applies to biomass units constructed after 9/18/78.
3 Under Title IV of the CAAA-90, SO_2 emissions (ton/yr) may not exceed the number held by the owner. Starting 1/1/95, utilities receive annual allowances based on a 2.5 lb/MMBtu emission rate using 1985 fuel consumption quantities
4 Regulations will be set by the year 2000 for major sources

Source: Antares (1993)

Table 12 shows the regulations for boilers that combust agricultural residues (assuming Subpart Db NSPS applies), regulations for California for wood-fired boilers, and regulatory trends. The EPA has been directed to formulate new NSPS emission requirements for industrial and commercial boilers, but its timetable and types of standards are unknown.

In addition to NSPS, PSD standards for new facilities in attainment areas apply. The threshold for an agricultural residue-fired boiler is 250 tons/year for any criteria pollutant (i.e., CO, HCs, NO_x, SO_2, and PM-10). PSD review includes a BACT review and air quality dispersion modeling.

The EPA is conducting a study to determine whether HAPs from electric utility steam-generating units (large agricultural residue boilers could fall under this jurisdiction) need regulating. This study was due in November 1993, but recent correspondence indicates it will not be completed until November 1995 (Kilgroe 1993). HAP regulations for electric utility steam-generating units could have a strong impact on MACT requirements for large agricultural residue boilers.

Emission Standards for Volatile Organic Liquid Storage Vessels

NSPS for VOCs from liquid ethanol storage are in 40 CFR Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced after July 23, 1984. The standards contain detailed requirements for floating roof tanks that would be required to store ethanol at the biomass-to-ethanol facility.

Solid Waste Regulations

Solid waste in the United States is regulated at the federal level under the Resource Conservation and Recovery Act (RCRA), passed in 1976 as an amendment to the Solid Waste Disposal Act. It is EPA's responsibility to develop regulations to carry out and enforce RCRA. Hazardous waste regulations that enforce RCRA are in CFR Volume 40, Parts 260–281. Most states have EPA authority to operate their own hazardous waste programs, and to adopt their own regulations, but they must be at least as stringent as EPA regulations.

Two sets of RCRA regulations—those that govern the combustion of hazardous wastes in boilers and industrial furnaces, and those that govern the disposal of bottom ash from incinerators and boilers—could have a major impact on biomass-to-ethanol facilities.

Regulations That Govern the Combustion of Wastes in Boilers and Industrial Furnaces

The biomass-to-ethanol scenarios that use a boiler include combusting wastes such as acetaldehyde that are considered hazardous under RCRA, so their treatment and disposal is regulated under RCRA (because this is a method of disposing or treating a hazardous waste). Recently, a number of changes have been made in the regulations that govern the combustion of hazardous wastes in boilers and industrial furnaces.

The EPA issued a ruling (which took affect August 21, 1991) that affects the incineration of nearly 2 million tons of hazardous waste in boilers and industrial furnaces (BIFs) (56 CFR 7134). BIFs were previously exempt from the federal hazardous waste rules because the process of combusting hazardous waste in BIFs for energy recovery or to make a product was considered recycling. Under the new RCRA regulations, BIFs will now be required to meet many of the same requirements as do hazardous waste incinerators, which are among the toughest EPA permits to obtain. Although EPA has stated that BIFs will be required to meet standards equivalent to hazardous waste incinerators, EPA has granted existing BIFs interim operating status while EPA and state officials decide on the best way for BIFs to meet more stringent standards and how to enforce these standards (EPA was sued over the initial rulemaking).

Because future BIF standards and permitting requirements will probably be very stringent, biomass-to-ethanol facilities should be designed, if possible, to avoid having to meet the BIF regulatory requirements. Three methods under the existing federal regulations could provide regulatory relief for biomass-to-ethanol facilities. They are, in order of increased regulatory requirements:

Table 12. FBC Regulatory Limits for New Facilities (29 MW and Higher)

		Comments	
Pollutant	**Federal Standard/ Regulatory Context**	**Sample State Limits (Regulation/State)**	**Regulatory Trends**
CO	250 ton/yr (CAAA-90, Title 1)[1]	0.14 lb/MMBtu (CA)[2]	EPA to develop new NSPS standards for industrial and commercial boilers (before year 2000)
HC	250 ton/yr (CAAA-90, Title 1)[1]	0.24 lb/MMBtu (CA)[2]	Same as CO
NO_x	0.6 lb/MMBtu (NSPS); 250 ton/yr (CAAA-90, Title I)[1]	0.080 lb/MMBtu (CA)[2]	Same as CO
SO_2	1.2 lb/MMBtu (NSPS); 250 ton/yr (CAAA-90 Title 1)[1]	0.033 lb/MMBtu (CA)[2]	Same as CO
PM-10	0.03 lb/MMBtu (NSPS); 250 ton/yr (CAAA-90, Title 1)[1]	0.045 lb/MMBtu (CA)[2]	Same as CO
Metals	No current federal limits; emission limits to be set for major sources[4]		EPA study under way

1 PSD permit including BACT review required for emissions > 250 ton/yr
2 Permit emission standard issued for biomass-fired FBC (Donovan and Associates 1992).
3 Under Title IV of CAAA-90, SO_2 emissions (ton/yr) may not exceed the number held by the owner. Starting 1/1/2000, utilities receive annual allowances based on a 1.2 lb/MMBtu emission rate.
4 Regulations will be set by the year 2000 for major sources

1. The small-quantity on-site burner exemption (40 CFR 266.108),

2. The low-risk waste exemption (40 CFR 266.1109),

3. The waiver for destruction and removal efficiency (DRE) trial burn for boilers (40 CFR 266.110).

The small-quantity on-site burner exemption allows operators of facilities that burn hazardous waste in an on-site boiler to be exempt from most BIF regulations. To qualify for this exemption, the hazardous waste must have a minimum heating value of 5000 Btu/lb and "not exceed one percent of the total fuel requirement for the boiler on a total heat input or mass input basis, whichever results in the lower mass feed rate of hazardous waste" (40 CFR 266.108). Depending on the height of the stack, allowable burn rates of hazardous waste may be lower than 1% (a higher stack is better because it disperses pollutants better and results in lower ambient ground level concentrations). Of concern for biomass-to-ethanol facilities is the acetaldehyde that will be burned in the CFB (considered a hazardous waste because of its ignitability). A waste can be considered hazardous under RCRA if it has any of the following characteristics:

- Toxicity

- Reactivity

- Corrosivity
- Ignitability.

Both the low-risk waste exemption and the waiver for DRE trial burn for boilers would provide some regulatory relief, depending on how a specific state interprets and enforces RCRA. A requirement for both classifications is that a "minimum of 50 percent of fuel fired to the device shall be fossil fuel, fuels derived from fossil fuel, tall oil, or, if approved by the director on a case-by-case basis, other non-hazardous fuel with combustion characteristics comparable to fossil fuel" (40 CFR 260.109). Whether nonreacted solids that were to be combusted in a biomass-to-ethanol facility boiler could meet this last criterion would have to be determined by the state or regional solid waste agency.

As part of developing BIF regulations, EPA is looking for ways to remove disincentives to hazardous waste recycling. In developing an alternative regulatory scheme, EPA proposed four categories of secondary materials, one of which is energy recovery from clean fuels. EPA defined this category as recovery of energy from simple fuels with predictable products of incomplete combustion, which exhibit only ignitability (*Environment News*, March 1991). Although no standards for determining clean fuels have been finalized, one proposal, which indicates potential future clean fuel requirements, defines a clean fuel as one not listed as an acute hazardous waste by EPA, that has a minimum heating value of 5000 Btu/lb (8000 Btu/lb was also proposed), as well as other limits on total halogens, sulfur, and ash generated. These developments are mentioned here because methane would be burned in the CFB of a biomass-to-ethanol plant and could affect the regulatory status of combusting it; they could also affect the classification of burning acetaldehyde.

Regulations That Govern the Disposal of Ash from MWCs and Boilers

A recent memorandum from EPA headquarters to regional administrators stated that MWC ash is not subject to RCRA regulation as a hazardous waste. Therefore, EPA would not consider the bottom ash (ash from the boiler) from CFBs in MSW biomass-to-ethanol facilities a hazardous waste. However, states may classify bottom ash from an MWC as hazardous. This can, because of the high costs of disposing the ash, have a tremendous impact on plant costs.

Most states do not currently regulate MSW bottom ash as hazardous, although some regulate it as a special handling waste, which is somewhere between the two classifications. The requirements for managing a special handling waste vary from state to state, but generally include adequate safeguards on fugitive emissions, such as spraying ash piles to prevent fugitive dust emissions, and disposal in a special lined monomer (an isolated part of a landfill, but not a hazardous waste landfill).

States may adopt stricter requirements for disposing ash, especially fly ash, which is the particulates captured by the APC equipment (e.g., by a baghouse). Fly ash usually has a higher concentration of metals than bottom ash (because the metals vaporize and then condense in the scrubber for removal by the particulate control device). It can often fail a toxicity characteristic leachate procedure (TCLP), a test that determines whether, based on its potential to leach toxic metals, a waste is hazardous. The test is designed to mimic leaching conditions in a landfill. However, in a CFB boiler the fly ash is automatically combined with the boiler bottom ash, so there will be no fly ash.

The above discussion is based on unsorted and unprocessed MSW. The MSW for a biomass-to-ethanol plant is expected to be similar to refuse-derived fuel (RDF), which usually has a lower concentration of metals; hence, the ash is not considered a hazardous waste by most states. Combustion ash from agricultural residue CFBs would be less likely to contain metals that would cause the ash to be regulated as a hazardous waste, because agricultural feedstocks contain few metals. In this analysis, bottom ash from CFBs from biomass-to-ethanol facilities is not considered hazardous.

State Definitions of Wood Waste

State regulations vary widely on their definition of solid waste, and this can have an enormous impact on the air quality standards a facility must meet. State air pollution agencies usually have specific definitions for various wood fuels and may classify facilities according to the type of wood fuel used (Environmental Risk, Limited 1992). Permitting procedures are generally more difficult and standards more stringent (e.g., lower emission limits, additional controls, additional testing, and record-keeping requirements) for facilities that burn treated wood. The definition of treated wood varies from state to state, but generally consists of wood that has been painted, stained, or otherwise altered). A few states consider waste-wood combustion essentially the same as MSW incineration and permit a waste-wood combustion facility similar to an MSW incinerator. Other states distinguish wood-fired facilities from MSW incinerators, and do not regulate and permit them in the same way.

Except in California, clean wood-fired energy recovery facilities are classified as wood boilers or combustion equipment, compared to solid-waste combustors or incinerators. In California, all wood-fired facilities are regulated as resource recovery facilities, along with MSW incinerators, tire burners, and sludge incinerators; hence, they are subject to the same level of regulatory agency review and public scrutiny as solid-waste incinerators (Environmental Risk, Limited 1992).

A biomass-to-ethanol facility that uses agricultural residues as a feedstock would probably be regulated as an industrial facility that burns process wastes in a boiler (see BIF regulations described earlier), but could be regulated by states as a waste-wood combustor, whereby the definition of treated versus clean wood waste could affect the regulatory status.

Water Quality

The EPA has cooperated with states to establish discharge standards for specific pollutants for industrial facilities. These limits are based on the best available technologies (BAT) and the economic costs of compliance. The EPA enforces compliance through a permitting system run by individual states under the National Pollutant Discharge Elimination System (NPDES), and has established standards that apply to specific industries, including steam-generating units, to control 129 toxic pollutants.

In 1982, EPA issued effluent guidelines, pretreatment standards, and NSPS for steam electric power plants. Pretreatment standards require that industrial dischargers treat or remove all pollutants that could pass through a municipal treatment system untreated and adversely affect the performance of the system. Standards for toxic pollutants are emphasized in these regulations. In addition, many states have passed separate stricter regulations that govern water quality and pollutant discharges.

Table 13 shows the limitations on pollutant discharges from steam electric power plants. Although CFBs of biomass-to-ethanol facilities do not definitively fall under this category, the regulations indicate standards that can be expected of these facilities. The regulations for NPDES permits are not discussed because this analysis assumes all wastewater discharges would go to a POTW; avoiding the NYPDES permit is a benefit because it can be time consuming to obtain.

Regulations were passed in 1990 that restrict hazardous waste discharges to POTWs. They include discharge restrictions on the type of waste that can be discharged by an industrial facility to a POTW and notification requirements for industrial facilities that discharge more than 15 kg of nonacute hazardous waste/month to a POTW. The new regulations prohibit any discharges of petroleum oil, nonbiodegradable cutting oil, or products of mineral oil origin in amounts that are likely to interfere with pass-through treatment systems.

The new regulations specify a minimum level of control that POTWs must apply in dealing with significant industrial users, facilities that:

- Are subject to a categorical pretreatment standard (40 CFR Part 403)
- Discharge an average of 25,000 gallons/day of process water (excluding sanitary, noncontact-cooling, and boiler-blowdown wastewaters)
- Are designated significant dischargers by the POTW because their discharges may adversely affect POTW operations.

Minimum control mechanisms are required of all significant users that include effluent limits based on general pretreatment standards, categorical pretreatment standards, local limits, and state and local laws.

The Clean Water Act (CWA) is currently up for reauthorization in Congress. Therefore, new regulations could be passed to make pollutant discharge limitations stricter. New limitations will most likely be included in the CWA reauthorization. For example, toxic discharges of arsenic, nickel, cadmium, lead, and selenium can exceed the established water quality criteria for coal-fired power plant sources and may be subject to stricter discharge permit restrictions (Antares 1993).

Summary of EPA Regulations for Base-Case Configuration

The EPA regulations presented in the preceding three sections are very complex and difficult to understand, even for those at EPA who made them. To simplify this analysis, governing regulations and types of pollutants for primary process steps for the base-case scenario are presented in Table 14 (the numbering of the process steps corresponds to the process diagram shown in Figure 2). Also shown is the estimated regulatory burden for each emission type; this is based on experience with similar types of facilities and correspondence with EPA.

Because state environmental agencies interpret EPA regulations differently, there is no way to determine exactly how a biomass-to-ethanol facility would be regulated without submitting a permit application. Estimating regulations for new facilities, such as a biomass-to-ethanol facility, is difficult because no precedent has been set.

National Environmental Policy Act

The National Environmental Policy Act (NEPA) provides a mechanism for environmental review of federal activities. NEPA is a short general statute: it declares a national environmental policy and promotes consideration of environmental concerns by federal agencies (Ikonomou and Pacchione 1994). NEPA continues to be a primary basis for challenges to public and private development decisions, and is important to environmental activists because it gives a statutory basis to force review of federal decisions.

Federal actions, such as operating programs, constructing facilities, and funding others to perform actions that affect the environment, are undertaken directly by federal agencies. Actions that require federal money or a permit from a federal agency are subject to NEPA. Any projects considered significant under NEPA are required to prepare an environmental assessment (EA). A project that might have a significant environmental impact requires a detailed environmental impact statement (EIS). The EIS process requires:

- A public notice of intent for a project
- A scoping meeting with the public
- Publishing a draft EIS
- A final meeting or meetings.

The public plays an important role in the EIS process, which can incur significant costs. Federal actions that will not affect the environment may receive a finding of no significant impact, a public document that briefly explains why a project will not significantly affect the environment.

States may have their own state environmental quality act reviews, so a state EIS can meet state and federal requirements. States with their own environmental quality acts are listed in Table 15.

The main reason an EIS is feared by project developers is that it brings the public into the decision-making process, and can give opponents a way to stop the project. These issues will be discussed further in the section on siting a biomass-to-ethanol facility.

Table 13. EPA Effluent Limitations

Pollutant	BAT (mg/L)	
	Maximum (for any 1 day)	Average (for 30 consecutive days)
All discharges		
pH (except once-through cooling)		6.0–9.0
PCBs		No discharge
Low-volume wastes[c]		
Total suspended solids	100*	30*
Oil and grease	20*	15*
Bottom ash transport waste[1,2]		
Total suspended solids	100*	30*
Oil and grease	20*	15*
Fly ash transport water[2]		
Total suspended solids	200*	30*
Oil and grease	20*	15*
Chemical metal-cleaning wastes*		
Total suspended solids	100*	30*
Oil and grease	20*	15*
Copper	1.0	--
Iron	1.0	--
Boiler blowdown		
Total suspended solids	--	--
Oil and grease	--	--
Copper	--	--
Iron	--	--
Once-through cooling water		
Free available chlorine	--	--
Total residue chlorine	0.2	--
Cooling-tower blowdown		
Free available chlorine	0.5	0.2
Zinc	1.0	1.0
Chromium	0.2	0.2
Phosphorus	--	--
Other corrosion inhibitors	--	--
Other 124 priority pollutants (in added maintenance chemicals)	No detectable amount	No detectable amount
Coal-pile runoff		
Total suspended solids (promulgated in 1980)	50	--

1 Probable BACT limits shown with an asterisk; BAT withdrawn in 1982
2 Concentration/12.5. Use for mass limit set in 1974 BAT.
* Divided into nonchemical and chemical categories, 1982.

Table 14. Preliminary Summary of EPA Regulations for Base-Case Configuration[1]

Process Step	Primary Type of Emissions and Classification	Regulatory Jurisdiction	Expected Regulatory Burden[2]
Fermentation	Ethanol (air) VOC	CAAA-90—criteria pollutants, SIP plans for O_3 nonattainment	Low
Product/denaturant storage	Ethanol (air) VOC	CAAA-90—criteria pollutants, SIP plans for O_3 nonattainment	Low
Product recovery	Acetaldehyde, fusel oils (mostly liquid phase), hazardous waste	RCRA boiler rules for hazardous waste combustion, state solid waste regulations	Med/High
Fluidized bed boiler—air emissions	Criteria pollutants (e.g., NO_x, SO_x) and HAPs	CAAA-90 (NSPS, PSD, and Title III), sate BACT, RACT, LAER requirements	High
Fluidized bed boiler/APC—ash	Ash (solid waste)	RCRA and state hazardous waste rules	Med/Low
Solids separation	Effluent discharges to POTW	CWA pretreatment standards for effluent discharges	Med/Low

1 Other alternatives will be considered in subsequent sections
1 Evaluated in terms of relative difficulty to obtain permits

Table 15. States That Have Environmental Quality Acts

California	Puerto Rico	Connecticut
Hawaii	Texas	Indiana
Maryland	Virginia	Massachusetts
Michigan	Wisconsin	Minnesota
Montana	Washington	New Jersey
South Dakota	Utah	North Carolina

Environmental Regulation of Biotechnology

Background

The basis for regulating the domestic biotechnology industry is the 1986 Coordinated Framework for the Regulation of Biotechnology that was developed by the U.S. Office of Science and Technology of the Executive Office of the President. This framework uses existing laws to govern biotechnology and outlines the responsibilities and jurisdictions of federal agencies. It also provides the recommended containment standards for laboratory and large-scale research and production using recombinant microorganisms.

Under this framework, jurisdiction for regulating the biotechnology industry is divided among three federal agencies:

- The Food and Drug Administration (FDA), which reviews and permits foods, food additives, human drugs, biologics and devices, and animal drugs (Van Houten and Fleming 1993)

- The U.S. Department of Agriculture (USDA). Two services within the USDA, the Food Safety Inspection Service (FSIS), and the Animal and Plant Health Inspection Service (APHIS), administer most of its biotechnology activities. FSIS reviews and regulates food products from domestic livestock and poultry (Van Houten and Fleming 1993). Animal biologics, plants, seeds, plant pests, animal pathogens, and other regulated articles, such as genetically engineered organisms with genetic material from a plant pest, are reviewed by APHIS (Van Houten and Fleming 1993).

- The EPA, which regulates all releases of microorganisms into the environment under the Federal Insecticide Fungicide and Rodenticide Act (FIFRA) and the Toxic Substances Control Act (TSCA) (Harrington and Loeb 1993). FIFRA regulates microorganisms used as pesticides, and TSCA regulates those used for other commercial and environmental applications (Harrington and Loeb 1993).

In some cases, the oversight is shared between two agencies. For example, microorganisms that are also plant pests are addressed by EPA and USDA.

The current biomass-to-ethanol process design includes a recombinant *E. coli* to ferment the pentose sugars. Therefore, EPA would have jurisdiction over the facility under the provisions of TSCA. If one of the by-products were an animal feed, USDA review would also be required. For this analysis, only the regulations applicable to the current design (i.e., TSCA) are addressed. Following this discussion, a short description of the recommended containment standards is presented.

Toxic Substances Control Act

The TSCA was enacted in 1976 to regulate harmful chemical substances. It is an extremely broad law because almost everything can be classified as a chemical substance, which TSCA defines as "any organic or inorganic substance of a particular molecular identity, including any combination of such substances occurring whole or in part as a result of a chemical reaction or occurring in nature and any chemical element or uncombined radical" (40 CFR 720.3(c)). Some chemical substances, such as pesticides (but not pesticide intermediates), foods, food additives, drugs, cosmetics and their intermediates, tobacco and tobacco products, and nuclear substances, are exempt from TSCA regulation because they are regulated by other federal agencies. Mixtures are not considered chemical substances; the individual components of a mixture may be so classified and subject to regulation.

Under TSCA, any person who intends to manufacture or import a new chemical—one not listed on TSCA's Inventory of Chemical Substances—must submit a Pre-Manufacture Notice (PMN) to EPA 90 days in advance. The number of substances on the Inventory is significant; as of 1985, more than 63,000 chemicals (Korwek 1990). All naturally occurring chemicals are assumed to be on the Inventory. Once a substance is listed, any other importer or manufacturer of the substance will not be subject to PMN requirements. Exclusions from PMN are impurities, by-products made for no commercial purpose, incidental chemical products, and nonisolatable intermediates (40 CFR 720.30(h)).

When a PMN is submitted, EPA reviews it to determine the risk to human health and the environment. If EPA finds no unreasonable risk, the substance is approved for manufacture. If EPA makes no such finding, it may request further information or testing. It may also limit or ban production, or regulate production methods, or both. In the risk assessment, EPA is also required to consider the benefits to society of the substance. EPA defines risk as hazard x exposure. Thus, large releases of low hazard substances may be of greater risk than a small release of a relatively hazardous substance.

A PMN filing costs $2500 (40 CFR Part 700), unless the filer is a small business (annual sales of less than $40 million). The cost of a small business PMN is $100 (40 CFR Part 700). In addition to the filing fee, EPA estimates the cost of submitting a PMN for a conventional chemical is about $10,000 (Korwek 1990).

In 1984, EPA ruled that microorganisms are considered chemical substances (Clement International Corporation [CIC] 1993). As such, EPA could regulate them under the PMN provisions of TSCA (Maher 1993). The EPA considers intergeneric (containing DNA from different genera) microorganisms new chemical substances if they are not already listed on the Inventory. New intrageneric microorganisms formed through genetic engineering are not considered new chemical substances, and thus are not subject to PMN (CIC 1993). Similarly, naturally occurring microorganisms are assumed to be on the Inventory, and as such are exempt from PMN (CIC 1993).

Intergeneric organisms in contained systems, such as those used for fuel or enzyme production, are subject to PMN. The EPA has considered exempting this class (or a specific subset) from PMN, but has not yet done so (Korwek 1990).

Microorganisms formed by inserting chemically synthesized genes are treated as though the genes were from an organism (Korwek 1990). That is, if the genetic sequence on the synthesized gene is the same as a sequence that occurs in the same genus as the recipient, the resulting microorganism is intrageneric and not subject to PMN. However, if the synthetic gene sequence does not occur in the same genus, the organism is considered new and is subject to PMN.

Chemicals produced by microorganisms (engineered or not) are regulated the same as those manufactured by other methods (Korwek 1990). If the chemical is on the Inventory, a PMN is not required; if it is not on the Inventory, a PMN must be filed.

Formal data requirements for PMNs for microorganisms have not yet been developed (CIC 1993). The EPA has, however, developed a set of guidelines for PMN submission. The guidelines are intended to provide EPA with enough information to:

- Identify the organism and list it on the Inventory
- Assess the risk to human health and the environment (CIC 1993).

The following information (if applicable) should be included in the PMN:

- A description of the organism's construction
- The donor and recipient organisms (including taxonomy, genotype, and phenotype)
- The source and function of the DNA used to modify the recipient organism, methods of constructing the vector with the inserts, and the method of introducing the vector into the recipient organism
- A description of the resulting microorganism (including phenotype, genotype, and any toxicity testing performed)
- Potential environmental impacts and behavior of the strain
- A description of the production process
- An assessment of the exposure to workers and consumers

- Detailed protocols for an environmental release.

The PMN process for microorganisms has not yet been finalized, so the data requests are not mandatory. However, if EPA finds the data in the PMN submission to be insufficient for review, the submitter will be asked to clarify or supply more information.

The definition of new chemical substances under PMN excludes from review many microorganisms with potentially significant environmental impacts. Therefore, EPA proposed in the 1986 Coordinated Framework to regulate some microorganisms with another TSCA provision, the Significant New Use Rule (SNUR). SNUR addresses pathogens or intrageneric microorganisms that contain genetic material from a pathogen. However, it covers only environmental releases, not contained uses of these pathogens.

The EPA may issue a SNUR for any TSCA chemical substance—an individual chemical, a chemical category, or new and existing chemicals. After a SNUR is promulgated, prior notice is required for any significant new uses. The SNUR requirement is designed to allow EPA to evaluate and potentially regulate the use of a substance before the use starts.

Persons subject to SNURs must notify EPA at least 90 days before any new, nonagricultural use that involves the environmental release of engineered pathogens (Korwek 1990). USDA oversight may also be required if a plant or animal pathogen is released (Korwek 1990). If the pathogen is a pesticide, FIFRA review is required for releases. The cost of a SNUR submittal is the same as for a PMN.

There are currently no SNURs for microorganisms. Until some are promulgated, EPA requests voluntary reporting (Korwek 1990).

Intrageneric organisms that are not pathogens are not addressed by the PMN. Environmental releases of these organisms should also be reported to EPA under Section 8(a) of TSCA. Contained uses of these organisms are not regulated (Van Houten and Fleming 1993).

The EPA is proposing a revision of TSCA to better address the biotechnology industry. Primarily, the proposed modification would be a tier testing scheme for new biotechnology applications. The schemes would then be used to generate hazard and exposure data for risk assessments (McMillan and Finkelstein 1994). In this scheme are three types of technology applications: contained/closed technologies, semi-contained technologies, and open/uncontained technologies (McMillan and Finkelstein 1994). Contained/closed technologies are those in which the number of microorganisms released to the environment is small or unintentional, or both (CIC 1993). Bioreactors used for bioremediation, closed system fermentation for enzyme, and fuel production are examples of closed technologies. Semi-contained applications are where most microorganisms are retained; enhanced oil recovery and certain desulfurization processes are examples of semi-contained applications (CIC 1993). Open technologies such as mineral leaching, ore mining, and bioremediation, make no attempt to retain the microorganisms (CIC 1993).

Proposed tier testing schemes for each technology were recently developed at an EPA workshop. The schemes are very similar and are described below (McMillan and Finkelstein 1994):

Tier 0: A PMN should be submitted and all applicable information supplied so EPA can assess the risk (i.e., hazard x exposure) and perform a risk-benefit determination. If the information is insufficient to estimate the risk or if other concerns are raised, the submitter must either supply additional information or proceed to Tier 1. If EPA determines no unreasonable risk, it approves the substance.

Tier 1: Tests are conducted for any concerns raised during the PMN review. Simple and relatively quick tests such as microtiter plates, test tubes, and microcosms are used. Worst-case exposure scenarios are evaluated. If the original concerns are resolved, the substance is determined to present no unreasonable risk and the application is approved. If not, the submitter can provide more information, perform more Tier 1 tests, or proceed to Tier 2.

Tier 2: More complex tests are required, but they would still be well controlled and contained. Ecological effects are studied in greater detail using complex microcosms and mesocosms. As with Tiers 0 and 1, if EPA determines that all concerns are resolved, it approves the application. If not, the submitter can either perform additional tests or proceed to Tier 3.

Tier 3: Open or limited field testing in selected environments is conducted. Monitoring or containment, or both, are used. This is the final level of testing. If all concerns cannot be resolved, the substance presents an unreasonable risk and would not be approved.

Containment Issues

The 1986 Coordinated Framework also provided guidance on containing recombinant microorganisms in large-scale fermentations. This guidance mirrored that in the National Institutes of Health (NIH) *Guidelines for Research Involving Recombinant DNA Molecules.* In 1988 and 1991 the guidelines were modified (Van Houten and Fleming 1993). The current guidelines (*Federal Register* 1991) include four containment levels:

- Good Large Scale Practice (GLSP)
- Biosafety Level 1—Large Scale (BL1-LS)
- Biosafety Level 2—Large Scale (BL2-LS)
- Biosafety Level 3—Large Scale (BL3-LS.)

GLSP standards are roughly equivalent to GILSP (Good Industrial Large Scale Practice) standards developed earlier by the Organization for Economic Cooperation and Development (OECD). These standards describe a level of physical containment for large-scale research or production that involves viable, nonpathogenic, and nontoxigenic recombinant strains derived from host organisms that have an extended history of safe large-scale use (*Federal Register* 1991). GLSP containment is also recommended for organisms that have built-in environmental limitations that permit optimal growth in the industrial setting, but only limited survival without adverse consequences in the environment.

If an organism does not qualify for GLSP (i.e., viable organisms that contain recombinant DNA molecules requiring BL1 containment at the laboratory scale), then the BL1-LS level of physical containment is recommended (*Federal Register* 1991). BL2-LS and BL3-LS are recommended for the large-scale use of recombinant microorganisms that would require BL2 and BL3 containment, respectively, at the laboratory scale. No provision has been made for large-scale research or production of viable recombinant organisms that require BL4 containment at the laboratory scale. If necessary, NIH will establish the requirements individually (*Federal Register* 1991).

GLSP standards are significantly less expensive than BL1-LS. Table 16 compares the standards.

These standards are only guidelines, but they are widely accepted by industry and the Organization for Economic Cooperation and Development (McMillan and Finkelstein 1994). A current problem, however, is that very few organisms designated by EPA meet the criteria for GLSP. Identifying organisms that meet these criteria would reduce the need for advanced tier testing (McMillan and Finkelstein 1994).

Summary of Environmental Regulations of Biotechnology

Biotechnology in the United States is regulated with the 1986 Coordinated Framework. For contained uses of intergeneric microorganisms, TSCA reporting and review requirements apply. The TSCA regulations are currently being modified to include a tier testing scheme that should standardize the permitting process. Identifying organisms that meet GLSP criteria by EPA would be a major step toward more widespread use of recombinant technology.

Regulating and Controlling Odors

Several process areas in a biomass-to-ethanol facility may generate odors. The most probable significant sources of process odors are fermentation, feedstock storage, and wastewater treatment. Controlling potential odors is very important to the overall success of a biomass-to-ethanol facility. Other industries have experienced significant setbacks caused by odor concerns. For example, in the 1960s, several MSW facilities were closed because of odor problems (Haug 1993).

Odor complaints comprise a large number of the citizen complaints received by environmental agencies (EPA 1992). Many odorous releases may be harmless, but people generally believe that "if they can smell it, it must be bad" (EPA 1992). Thus, odor control is a significant concern for any facility.

Odor regulations are generally local (never federal) statutes, and some areas use qualitative standards to control odor. In these cases, terms such as "interfering with life or property" are used to maintain an odor-free environment. Facilities in these areas will have a difficult time designing the facility, as there is no rigid standard. Any facility will release odors, and a qualitative standard implies that all are unacceptable. Thus, a trial-and-error odor control strategy, in which the community complains and the facility managers try to address its concerns, must be used. Odor problems are "solved" when the level of complaints reaches a politically acceptable level (Haug 1993).

Some communities have developed quantitative odor standards. In these cases, the facility and community acknowledge there will be odors, but they establish an "acceptable odor risk" (Haug 1993), which allows the communities to choose an odor level. The facility then uses atmospheric models and the expected emission levels of odorous compounds to predict the odor level in the community. The facility can then engineer the emissions to meet the acceptable odor level. One problem, however, is that the synergistic effects of odorous compounds cannot be modeled; only the individual effects of each component can be assessed. In any case, a quantitative approach to the control of odors results in a system that is easier to implement and provides a good working relationship between the community and the facility.

Several methods of controlling odors are available:

- Absorption in a scrubber. In the biomass-to-ethanol process, this type of control would apply to fermenting and aerating system off-gases. Absorption is primarily effective for controlling acid gases and soluble organics.

- Condensation. Although this could also be used on the fermentation off-gases, a packed tower absorber is likely more cost effective. Condensation is generally cost effective only with very high concentrations of odorous compounds.

- Carbon adsorption. In the current design, carbon adsorption is used after the packed tower scrubbers aerate the off-gases. It is highly effective for reduced sulfur compounds and volatile organics.

- Thermal, chemical, and biological oxidation. In the current design, none of these control methods has been selected. Thermal oxidation in the boiler, however, may be an appropriate control method for the feedstock handling area. Odor sources can be masked and neutralized with chemical agents. This method is used after odor problems have been encountered.

- Dilution and dispersion.

Odor management should be included in the earliest stage of planning and design. The current biomass-to-ethanol design includes several odor control strategies, but a more detailed study of odor concerns is warranted. Several strategies should be investigated. In addition, when potential facility sites are named, the local ordinances should be determined; if any similar facilities are in the area, they should be studied for their odor control measures.

Early involvement of the community is critical in an odor control strategy. An acceptable odor risk should be developed with the community and used as the standard for the facility design.

Table 16. Comparison of GLSP and BL1-LS Standards

Criterion	GLSP	BL1-LS
1. Culture fluids are not removed from a system until all organisms are inactivated	Not required	Required
2. Viable organisms should be handled in a system that physically separates the process from the external environment (closed system or other primary containment)	Not required	Required
3. Inactivation of waste solutions and materials with respect to their biohazard potential	Per environmental regulations	Required
4. Control of aerosols to prevent or minimize release of organisms during sampling, addition of materials, transfer of cells, and removal of material, products and effluents from a system.	Minimize using procedural controls	Minimize using environmental controls
5. Treatment of exhaust gases from a closed system to minimize or prevent release of viable organisms	Not required	Required
6. Closed system that has contained viable organisms not to be opened until sterilized by a validated procedure	Not required	Required

Source: Van Houten and Fleming (1993)

Environmental Issues of the Current Fuel Ethanol Industry

Background

More than 1 billion gallons of ethanol are produced annually by approximately 35 fuel ethanol facilities in the United States. For the most part, these facilities use corn as a feedstock; however, some use sorghum, millet, or other feedstocks. Two primary processes, wet and dry milling, are used to process corn. The environmental impacts from both types of facility are similar.

General Environmental Considerations

Environmental considerations for fuel ethanol facilities are generally the same as those for most manufacturing facilities: air emissions, water releases, odor, and solid waste disposal. The greatest potential impacts from these facilities are likely their air and water emissions.

The major sources of air emissions are the boiler flue gas, feedstock processing, by-product recovery and processing, fermentation off-gases, solvent storage, distillation, and fuel processing (Collins et al. 1980). Most fuel ethanol facilities produce their own steam from coal-fired boilers; some also have cogeneration facilities and supply their own electricity. Coal combustion produces air emissions of all criteria pollutants (SO_2, NO_x, CO, PM-10, VOCs, and lead). With proper controls, all pollutants can be maintained at lower than applicable emission limits.

Particulate emissions are controlled with an ESP or FF. SO_2 is controlled by scrubbing or injecting limestone into the beds. For most facilities, NO_x, CO, and VOCs are controlled through proper combustor operation (e.g., air-to-fuel ratio). Newer facilities or modifications to existing facilities have generally been required to have additional NO_x control such as SNCR (Calmess 1994).

Feedstock processing is another source of air emissions. Dust is generated during the transfer of grain into and out of the storage area (Collins et al. 1980). Milling also produces a significant quantity of PM-10 emissions. Trace amounts of pesticides are associated with corn and will be emitted on the particulates from both processes, but these emissions are considered negligible. Emissions from milling and grain transfer are controlled with a cyclone or baghouse. Dust is controlled not only for air quality concerns, but also because high concentrations of dust are fire and explosion hazards (Collins et al. 1980; Mulloney et al. 1982). Uncontrolled PM-10 emissions from grain processing are estimated at 12 lb/ton of grain (Mulloney et al. 1982). For a dry milling facility that produces 50 million gallons of anhydrous ethanol per year, this corresponds to an annual emission rate of 3264 tons. Following control (95%), this is reduced to 136 tpy.

Particulate matter is also emitted during the recovery and processing of by-products such as distillers dried grain and solubles (DDGS). DDGS is produced in the dry milling process by evaporating stillage mixed with the grain dust collected in feedstock processing. Because the drying process is usually done through direct contact with hot air, some particulate matter will be entrained in the gas stream and emitted to the atmosphere. Most (70%) of the PM is collected with cyclones and returned to the dryer. Controlled PM emissions from this process are estimated at 133 tpy for a 50-million-gallon dry milling facility (Mulloney et al. 1982). When the DDGS is sent off-site, fugitive dust emissions will be generated, but they are controlled with a baghouse to nondetectable levels.

Fermentation produces a significant quantity of CO_2, which entrains water, ethanol, and other trace organics in the fermentation broth (e.g., aldehydes and fusel oils) into the atmosphere. Approximately 1% of the ethanol produced may be emitted to the atmosphere during fermentation (Mulloney et al 1982). Most (more than 98%) of the ethanol can be recovered using a water scrubber, but almost no CO_2 is captured. The scrubber effluent can be returned to the process for ethanol recovery. Controlled ethanol emissions from a 50-million-gallon dry milling facility are estimated at 37 tpy. Emissions of other organic compounds are negligible.

Storing products and denaturants (generally gasoline) also results in air emissions of VOCs because of working and breathing losses. These emissions are minimized by internal floating roof tanks. Another source of air emissions is a solvent such as benzene or cyclohexane used as an entrainer for ethanol dehydration. These emissions are generally very small and are controlled with vent condensers (Waits and Elmore 1983). This source of emissions, however, is becoming more important because of the solvents' toxicity (Calmess 1994); benzene is a carcinogen and is included as one of EPA's 189 HAPs under CAAA-90. The final source of air emissions from a fuel alcohol facility is from fuel receiving, conveying, and storage. These emissions can be controlled by sprays and enclosures. Uncontrolled emissions of coal dust from a facility that produces 50 million gallons of ethanol per year are estimated at about 50 tpy (Mulloney et al. 1982).

Wastewater is another important environmental consideration for current fuel ethanol facilities. The major sources of wastewater are by-product processing, distillation/dehydration, air pollution control, cooling tower blowdown, waste treatment effluent, and fuel storage run-off and infiltration.

Condensate from product drying (e.g., fiber, DDGS) is the largest volume liquid effluent from the fuel ethanol production process. This stream will have a high concentration of organic matter that has a high biochemical oxygen demand (BOD) and an acidic pH (Waits and Elmore 1983). Total solids of this stream is estimated at 130 ppm with a BOD of 650 (Mulloney et al 1982); the pH is estimated at 3.9 (Waits and Elmore 1983). This water must be treated before being released or reused.

Wastewater is also produced from the distillation/dehydration process. A significantly lower quantity of wastewater is produced in this area, but it has about twice the solids and BOD as the condensate (Waits and Elmore 1983). At pH 5, it is also slightly acidic (Waits and Elmore 1983).

Another source of water releases is boiler blowdown; this stream has a relatively high mineral content, but the overall volume is low, about 10% of the condensate stream (Waits and Elmore 1983).

The effluent from SO_2 scrubbers is acidic and high in solids, with a volume about the same as boiler blowdown. Cooling tower blowdown is another source of wastewater from a fuel ethanol plant. Although it is a high-volume discharge, it has relatively low concentrations of pollutants. The total solids (TS) for this stream is estimated at 800 ppm, the BOD is 30 ppm, and the sulfate is about 500 ppm.

These releases are generally treated at an on-site facility. Typical characteristics of the influent to the treatment plant for a facility that produces 50 million gallons of ethanol/year are shown in Table 17.

Following treatment, the effluent from the facility will have significantly reduced levels of all pollutants. Waits and Elmore (1982) estimate that the wastewater treatment plant effluent contains about 300 ppm TS, 50 ppm sulfate, and a BOD of 3 mg/L. Thus, although the volume of this stream is significant, its overall impact will be small because of the low pollution levels.

The final source of water pollution considered in this analysis is coal pile run-off and infiltration. Quantifying these sources is difficult because they depend on location, rainfall, and other factors (Mulloney et al. 1982). In any case, the waste stream is generally acidic and has elevated levels of trace metals (Waits and Elmore 1983).

Releases of solid wastes from fuel ethanol plants include boiler ash, flue gas desulfurization solids, and water treatment sludges. The volume of boiler ash and flue gas desulfurization solids will be significantly greater than the sludges. None of the wastes is considered hazardous or difficult to dispose.

Table 17. Typical Characteristics of a Fuel Ethanol Wastewater Treatment Facility

Item	
Volume	760 gpm
TS (ppm)	843
Suspended solids (ppm)	104
BOD	246
pH	4-8

Source: Mulloney et al. 1982

Environmental Case Studies for Actual Fuel Ethanol Facilities

There are about 35 operating fuel ethanol facilities in the United States. Numerous other facilities were built, but have ceased operations. An examination of the environmental problems and concerns of these facilities provides a useful basis for projecting the potential environmental impacts of a new facility. Four facilities will be evaluated; two are currently operating, and two have shut down.

Three fuel ethanol facilities (New Energy Company of Indiana [NECI], Tennol Energy Company, and Agrifuels Refining Company) were constructed in the 1980s under the DOE Alcohol Fuels Loan Guarantee Program. NECI, located in South Bend, Indiana, uses dry milling to produce ethanol. It began full operation in 1985 and continues to produce more than 50 million gallons of ethanol per year. Tennol is located near Jasper, Tennessee; it has a capacity of 25 million gallons/year of ethanol from corn using modified wet milling. The Tennol facility also began operating in 1985, but because of technical problems never achieved more than 50% of capacity. In 1988, the facility was shut down. The Tennol facility is considered to be one of the most likely facilities to reopen. Agrifuels, located near New Iberia, Louisiana, produces ethanol from molasses. It began operating in 1987, but because of financial problems was soon shut down. No information is available regarding this facility's potential to reopen.

Archer Daniels Midland (ADM) is the largest producer of fuel ethanol in the country; it produces about 70% of the total domestic ethanol. ADM has a large wet milling facility in Decatur, Illinois, with an annual capacity of 280 million gallons of ethanol.

A study was conducted recently to determine whether the actual environmental impacts of the three DOE-funded facilities corresponded well with the anticipated environmental impacts as listed in their EAs (Hunsaker et al. 1989). A representative of the ADM facility was contacted for information about the Decatur facility.

The major environmental impacts are air quality, water quality (surface and groundwater), water use, ecology, land use, and socioeconomics (typical categories analyzed in an EA). Table18 summarizes the probability of an impact at a typical fuel ethanol facility and the severity of the consequences.

Estimating the severity of the consequences for many impacts such as air releases assumes all permit conditions and workplace standards are met. Socioeconomic impacts in the form of expenditures were generally determined to be beneficial (Hunsaker et al. 1989).

Table 18. Predicted Impacts and Severity of Consequences for Fuel Ethanol Facilities

Impact	Probability of Occurrence	Severity of Consequences
Criteria Pollutant Air Emissions	High	Low to Moderate
Water Use	High	Low to Moderate
Groundwater Pollution	Low to Moderate	Moderate to High
Wastewater Discharges	High	Moderate to High
Habitat Disturbance	Moderate	Low
Endangered Species	Low	Low
Land Use	High	Low to Moderate
Noise	High	Low to Moderate
Conflicts with Cultural and Archaeological Values	Low to Moderate	Low
Expenditures (Wages, Salaries, Goods, and Services)	High	Moderate
Demand on Public Services	Low	Low
Traffic Congestion	Moderate	Low to Moderate
Occupational Exposure to Chemicals	High	Low
Geology/Soils	Low	Low

Source: Hunsaker et al. (1989)

Air Quality Impacts

The major air quality impact for each facility is its boiler. Each facility produced its own steam, and ADM has a 150-MW cogeneration facility that also produces electricity for the process. NECI and Tennol have coal-fired boilers; Agrifuels uses bagasse for fuel. ADM is permitted to burn coal and tires in its six fluidized bed boilers (Calmess 1994).

All facilities were required to obtain PSD permits because all were considered to be major sources of SO_2 and NO_x. ADM also has a state operating permit (Calmess 1994). The operating facilities (ADM and NECI) are in compliance with their PSD permits. Agrifuels and Tennol reported no significant air quality issues. Both Agrifuels and Tennol significantly underestimated the emissions of some criteria pollutants in the original EAs, but this was not considered significant because the emission levels were still relatively low (Hunsaker et al. 1989). Agrifuels had to modify its permit because of the changes in boiler fuel and processing scheme. Compliance with ambient standards could not be verified with data other than modeling runs because ambient monitoring was not required for any of the facilities (Hunsaker et al. 1989).

ADM is expanding its operation and adding two fluidized bed boilers. The new boilers have the same permitting requirements as the older boilers, but the allowable emission rates have significantly decreased. The new boilers will have limestone injection for SO_2 control, SNCR for NO_x control, and a baghouse for particulate control (Calmess 1994).

The one significant unexpected atmospheric impact of these facilities was the odorous releases from NECI. The odors were determined to be from the rotary kiln dryers (for DDGS) and from the evaporator. To combat these problems, the facility installed a dry chlorine injection system on the dryer and evaporator stacks; this change is estimated to reduce odors by about 75% (Hunsaker et al. 1989). The ADM facility has also had a few isolated cases of odor complaints from grain drying and other operations in the wet milling facility (Calmess 1994). This is not a great concern because corn wet mills have been in the area since the turn of the century and the population is desensitized (Calmess 1994). Potential odor effects should be evaluated in any new fuel ethanol facility, especially those upwind of metropolitan areas or that will be located in an area that does not already have grain processing or other similar operations.

Water Resource Impacts

Impacts to water resources are water consumption, discharges to surface and groundwater reservoirs, impacts to aquatic ecosystems, and developing of wells. For the most part, no significant adverse impacts in terms of water consumption were encountered for the DOE-sponsored facilities; water demand for these facilities was within acceptable limits (Hunsaker et al. 1989). No information was obtained regarding water consumption at the ADM facility.

The impact of discharges to surface waters had significant effects. NECI underestimated its total wastewater discharge and BOD by a factor of 17. This error, in conjunction with an undersized local POTW, caused the POTW to exceed its NPDES and state permits. The POTW has since upgraded its facility and increased its capacity, and NECI has increased its water conservation and wastewater spill control measures so the POTW can now handle the facility's waste stream. The Indiana Department of Environmental Management (IDEM), still feels the retention time at the facility is too short to ensure adequate treatment (Hunsaker et al. 1989).

Agrifuels has also had problems with its wastewater stream. Even though the facility has operated in startup and maintenance modes only, it has not met its NPDES permit limits for BOD, TSS, ammonia, and total nitrogen (Hunsaker et al. 1989). The average BOD was more than 50 times the permitted value, and the average TSS was more than 60 times the permitted value. The facility has also had excursions from the permitted levels for oil and grease and dissolved oxygen (Hunsaker et al 1989), and has experienced difficulty because of the odor and dark color of its effluent. Even if the facility meets its NPDES permit limits, it could be classified as a public nuisance and would have to take corrective actions.

The ADM facility has had no significant problems with its wastewater discharges. The Decatur facility has a large (7–10 million gallon/day) wastewater treatment facility composed of AD, equalization basins, clarifiers, and a finishing or polishing pond (Calmess 1994). The effluent from the treatment plant is so clean that some is recycled back to the process and some is used to irrigate an adjoining farm (Calmess 1994). The remaining water is released to a POTW.

Ecosystem Impacts

All DOE-sponsored facilities predicted they would have no significant negative impacts to the surrounding ecosystems. In the case of NECI, this has been true; in fact, the facility may have improved the aquatic and terrestrial ecology (Hunsaker et al 1989). Salmon now thrive in the adjoining river, and construction activities have created habitats for waterfowl and small mammals (Hunsaker et al. 1989). No significant adverse impacts to the surrounding ecosystems were caused by the Tennol facility. Some unanticipated ecological impacts were caused by the Agrifuels facility. Almost 12,000 fish were killed when stillage was accidentally dumped into a creek by a Tennol subcontractor. The second impact was the construction of a barge terminal that was not included in the original EA.

There was concern that the terminal would affect some endangered species of mussels, but this was unsupported (Hunsaker et al 1989). No information was obtained regarding impacts to the ecosystem from the ADM facility.

Socioeconomic Effects

The projected socioeconomic effects are projected to be job creation, increased demand for services, and increased traffic. These were considered to be generally positive, and no significant unexpected events occurred.

Land Use Effects

Land use effects are land use changes, solid waste disposal, and potential conflicts with archaeological or historical resources. Small unexpected changes, including CO_2 processing and land farming of sludge in the proposed land use, were encountered at the DOE-sponsored facilities. Solid waste disposal at each facility was not a significant issue when the EAs were prepared. This assumption was shown to be valid for all facilities. The ADM facility has no significant waste disposal issues; it generates no hazardous wastes, and all solid wastes are landfilled (Calmess 1994). No effects to cultural resources were anticipated for any facility in the EAs, and none were encountered.

Conclusions

Fuel ethanol facilities have many of the same environmental concerns as other manufacturing facilities. The two greatest environmental effects are air emissions and wastewater releases. Regulated air pollutant emissions can be readily controlled, and no facility had significant problems in this area. Odor control, however, may be more difficult.

Adverse impacts to water resources is another potential environmental concern for ethanol facilities. Two facilities, NECI and Agrifuels, had significant problems in this area. In both cases, the wastewater was not properly characterized in terms of quantity, quality, odor, and color. ADM has an extremely successful wastewater treatment system. Not only can it meet its permitted water limits, but it minimizes water demand by recycling some treated water to the process and using it for irrigation. Good wastewater treatment is essential to successfully operate any fuel ethanol facility.

Analysis of Environmental Permitting and Pollution Control Equipment

Background

Based on the regulatory analysis presented earlier, emissions for the scenarios are presented, and federal permitting requirements and pollution control technologies are discussed. Emissions that would have the most significant effect on permitting and pollution control requirements are focused on in this section. In many cases, these are air emissions associated with the CFB boiler. Emissions data are taken from estimates based on process engineering estimates for a biomass-to-ethanol facility or from existing CFB plants. Additional emissions data are in the 1992 Full Fuel Cycle Analysis (base case only) (NREL 1992). The base-case scenario is discussed first for the MSW feedstock and compared to Scenarios B, C, and D. The base-case scenario for agricultural residues is then discussed.

Base Case with MSW

Preliminary emissions for the base case 2000-tpd MSW CFB are presented in Table 19. Also included in the table are the corresponding federal regulations, the BACT estimate, the estimated efficiency for the APC equipment, and the total tpy of criteria pollutants. The stream numbers correspond to the process flow diagram in Figure 2.

Air

The base case has several releases to the environment. The four primary sources of air emissions are the fermentation off-gases, the storage tanks, the boiler, and the aerobic wastewater treatment reactor.

The three air emissions sources not from the boiler are briefly discussed, then the boiler emissions—of primary concern from an environmental standpoint—are discussed in detail.

The fermentation off-gases are more than 90% CO_2, and about 1.2% of the ethanol will be entrained in the off-gases. Most (99.5%) of this ethanol is recovered in a water scrubber, and the liquid effluent is returned to the process to recover the ethanol. Because the scrubber is part of the system design not necessarily driven by environmental regulations, it is not described in detail. Trace amounts of acetaldehyde may also be emitted in this stream, but the quantity is less than 1 lb/year (NREL 1992), and will not be discussed. Controlled ethanol emissions from this source are 14 tpy.

The facility stores large quantities of ethanol, gasoline for denaturing, and diesel fuel. Each tank emits VOCs because of working and breathing losses, which are minimized by internal floating roof tanks. Estimated emissions from the tanks are small, less than 1.5 tpy (1.36 tpy of VOCs from the gasoline storage tank, 0.004 tpy from the diesel storage tank, and 0.7 tpy from the ethanol storage tank) (NREL 1992). These emissions were estimated by using EPA's AP-42 emission factors (EPA 1985).

Air emissions are also associated with the aerobic reactor. Most organics will be degraded in the anaerobic digester, but some may stay dissolved and can be entrained in the aeration ponds. In addition, some of the H_2S formed during AD can remain in solution and be emitted from the aerobic reactor. Therefore, the off gases will be controlled with a series of two scrubbers (caustic and acidic) followed by an activated carbon bed. This system is expected to control VOC and H_2S emissions to nondetectable levels.

Because very few CFB boilers are used at MSW facilities, emissions data for this type of facility are limited. Permit limits for planned CFB facilities are shown in Table 20. The Erie, Pennsylvania, facility uses limestone injection in the bed, duct injection upstream of the baghouse, and SNCR, and the Robbins facility uses a spray dryer with SNCR.

BACT determinations for APC equipment are based on operating experience, permitted and achievable emission limits, and previous data (including costs) from existing systems. The EPA did not consider CFB facilities in its determination of BACT for new MWCs as outlined in its draft regulations. Because CFBs are inherently different from the more common waterwall and starved air MSW technologies, the BACT determination for CFB systems is different.

Table 19. Emissions for MSW Base Case

		MSW 2000 tpd New Facility							
		579	MMBtu/h						
	Stream #	**Pollutant**	**Uncontrolled Emission (ppmvd) @ 7% 02**	**Uncontrolled Emission Mg/dscm @ 7% 02**	**Federal Standard**	**BACT Estimate**	**Removal Efficiency**	**Controlled Emission Rate**	**tons/ yr**
air	1	EtOH VOC	57	110	none	CTG			14
	2	VOCs	na	na	none	CTG			2
	4	NO_x	205	392.000	180 ppm	SNCR	65%	71.75 ppmv	355
		SO_2	190	507.000	30 ppm/80%	SD/FF	80%	38 ppmv	131
		PM-10	na	2900.000	34 Mg/dscm	FF	99%	29 Mg/dscm	76
		lead	1.42E-03	0.012	0.16 Mg/dscm	SD/FF	0.95	7.1E-05 lb/h	0
		CO	126	147.000	100 ppm	GCP	0	126 ppmv	381
		VOCs	37	25.000		GCP	0	37 lb/h	64
		HCl	20	30.000	25 ppm/95%	SD/FF	0.95	1 ppmv	4
		mercury	na	na	0.10 Mg/dscm/80%	C/Na2s inj.	0.8	na	<1
		cadmium	na	na	0.02 m/dscm	SD/FF	0.97	na	<1
		dioxins/furan	na	na	30 ng/dscm	SD/FF	0.97	na	<1
		acetaldehyde	0.21	0.380	none	GCP	0	0.224 lb/h	1
		formaldehyde	0.19	0.230	none	GCP	0	0.14 lb/h	1
solid	3	acetaldehyde	na	na	1% BIF[2]			1.13%[2]	
waste		fusel oils	na	na	BIF-NA			NA	
	5	ash	trace metals	na	TCLP				

Table 20. Permit Limits for Planned CFB Facilities

Pollutant/Parameter	Erie, PA Facility Existing Permit from 1987 (Minott 1991)[1]	Robbins, IL Facility Proposed Limits[2]
Particulate (total)	0.015 gr/dscf	0.010 gr/dscf
Particulate (PM-10)	No limit	0.010 gr/dscf
HCl	30 ppmvd (1-h), or 90% reduction (1-h)	25 ppmvd (24-h)
SO_2	50 ppmvd (1-h), or 70% reduction (1-h)	30 ppmvd (24-h)
CO	100 ppmvd (8-h), or 32 lb/h	100 ppmvd (4-h)
Combustion efficiency	99% (1-h)	99.9% (1-h)
Dioxin/furan	2.0 ng/Nm^3 toxic equivalents (EPA method)	BACT
NO_2	No specific limit	130 ppmvd (24-h)
Opacity	Less than 10% (6 min)	Less than 10% (6 min)
Combustion temperature	Minimum 1450°F	Minimum 1500°F, gas residence time > 3 s

1 All concentration values are calculated at 7% O_2.
2 (Commercial Operation will begin 1996) (Campbell et. al)

Future BACT (1998–2000 timeframe) for NO_x is conservatively estimated to be SNCR. This is based on an emission limit of 180 ppmv as promulgated in the draft NSPS regulations for new MWCs. Some CFB facilities would be very close to this emission rate with no NO_x control, typically in the 150–200 ppmv range (Campbell et al. 1993). (The lower furnace temperature of CFBs produces lower NO_x than do conventional combustors, and the introduc- tion of combustion air in stages; i.e., different elevations, also reduces NO_x.) However, the emis- sion limits for the Robbins facility is 130 ppmv (see Table 20), so new facilities should equal this emission rate. Furthermore, the emphasis on NO_x control by states is a growing trend. Areas of O_3 nonattainment could have BACT requirements below the 180 ppmv NSPS. Severe nonattainment areas could require stricter NO_x control than SNCR, such as selective catalytic reduction (up to 90% reduction), but this technology has not been used successfully on MWCs (partly because the catalyst bed must be located downstream of the APC so it will not corrode). Because the total tpy of NO_x emissions is greater than 250, the PSD review process would be triggered, and a PSD permit and a BACT review would be required.

BACT for SO_2 control in a CFB would be limestone injection in the CFB followed by collecting parti- culates in the baghouse. Existing NSPS regulations require 70% reduction in SO_2 emissions, which could be achieved by injecting limestone in a fluid- ized bed boiler (for example, the Tacoma fluidized bed reactor uses this technology and can meet the 70% SO_2 requirement) (McCarty and Colville 1991). It is unclear whether more stringent SO_2 standards (e.g., 30 ppmv or 80% reduction as re- quired in the draft NSPS) could be met with a CFB and limestone injection and a baghouse.

HCl can be controlled by limestone injection in the bed and in-duct injection of hydrated lime upstream of a baghouse or use of a spray dryer. These are the same controls for SO_2 (both pollutants require the same type of control because both are acid gases). Extensive testing at the Sundsvall facility (a CFB combustor that burns RDF) in 1985 and 1988 showed that both SO_2 and HCl could be controlled by injecting limestone into the CFB.

However, the tests also showed excessive NO_x at the limestone injection rates needed to control HCl to within acceptable limits. Furthermore, the reactions that involve SO_2 capture occur rapidly at the typical bed/furnace operating temperatures, and the HCl absorption reactions are more likely to occur at the lower temperatures found downstream of steam generation (Minott 1991). Therefore, SO_2 can be directly captured in the CFB at limestone rates that do not adversely affect NO_x generation, and HCl can be captured by lime injection upstream of the bag- house using a venturi type nozzle for injection (this type of technology is considered BACT for acid gas control on small MWCs). Table 21 shows test re- sults from the Gotaverken CFB facility at Sundsvall, Sweden showing this phenomena (Minott 1991).

Both a spray dryer (without limestone injection in the bed) and limestone injection in the bed and directly upstream of the baghouse could be considered BACT for CFB MWCs for acid gases, but this analysis assumes that a spray dryer would be the best choice for acid gas control for a future MSW biomass-to-ethanol facility using a CFB because—

1. It has already been used on an CFB MSW facility in the United States and has set a precedent

2. It is currently considered BACT on more conventional waterwall and starved air MWCs

3. It would result in better control of HAPs (such as metals)

4. BACT is always becoming stricter and a spray dryer is a more conservative BACT estimate than limestone in both the bed and directly upstream of the baghouse.

BACT for other metals emissions, such as cadmium and lead, as well as for dioxins and furans, would be reduction of the flue gas temperature before capturing particulates in a baghouse. Many trace metals that volatilize at high temperatures (arsenic, cadmium, chromium, and nickel, and their compounds) as well as some organic HAPs, either nucleate homogeneously or condense on fly ash particles as the flue gases cool. The toxic particles formed by homogeneous nucleation are sub-micron size. Similarly, the toxic metals that condense on fly ash particles condense mostly on the fine particle fraction because of its greater total surface area; hence, by reducing temperatures before the baghouse (about 300°F), the toxic metals can be captured in the baghouse. This can achieve particulate removal efficiencies above 99% (Corbus 1989). Although ESPs could be used instead of baghouses as particulate control devices for many applications considered in this report, baghouses are emphasized because of their high collection efficiency for small particle sizes (and for other design reasons).

The pre-feasibility study conducted for the CFB biomass-to-ethanol facility (Radian 1991) contained a fluidized bed dryer to decrease the moisture content of gases entering the CFB. A potential problem with this is that baghouses cannot operate at temperatures much below 300°F (the dew point of the acid gases) because the FF will corrode. This has been an obstacle to these systems in the past. Therefore, the fluidized bed dryer should be reevaluated for this system; an ESP might not have the corrosion problems of the baghouse.

The EPA is developing emission rates for many toxic metals considered HAPs under Title III of CAAA-90, and many states have their own ambient air quality standards for toxic metals. However, the future standards developed for these HAPs, except for mercury, can probably be met in a CFB with a spray dryer.

Mercury concentrations in waste are decreasing, and are projected to be reduced even further in the near future because it is being continually reduced in the waste stream (e.g., elimination of mercury from consumer alkaline batteries). Recent EPA data estimate that mercury in the MSW stream will drop by 65% from 1989 to the mid-1990s (Kiser and Sussman 1991). Based on these estimates, mercury emissions could be controlled in the waste stream along with a dry scrubber. However, EPA has advocated combustion flue gas additives to control mercury. Tests completed by EPA and industry have indicated that activated carbon or sodium sulfide compounds enhance the capture of mercury on MWCs equipped with acid gas control systems (Feldman et al. 1993).

Table 21. Emission Test Results for Gotaverken CFB Facility at Sundsvall, Sweden, 1988[1]

APCs	Baghouse	Baghouse	FSI/BH[2]	FSI/BH	FSI/BH	FSI/BH
Furnace limestone injection (kg/h)	0	0	500	500	500	500
Emissions, ppmvd CO	9	9	18	4	5	13
NO_x	152	163	333	337	333	277
Dioxin TE[3]	6.2	7.8	0.7	0.7	1.0	1.4
HCl	285	324	19	13	14	10
SO_2	55	53	>3	>3	>3	>3

1 Fuel is 100% RDF; Sundsvall is a 200 tpd CFB facility operated at 95% of full load during all tests. Emission sampling and analysis is by Swedish test methods, which are similar to EPA-approved methods. All emissions are at 7% O_2.
2 Furnace sorbent injection/baghouse
3 Toxic equivalency

Injection of powdered activated carbon has been used successfully in MSW incinerators to remove mercury at rates of 50%–90% at operating temperatures of 250°–350°F. In one application, activated carbon injection into a spray dryer upstream of an ESP showed a substantial mercury reduction (Feldman et al. 1993). The most sensible control of mercury emissions could be to control the mercury in the waste stream before combustion, but EPA indicates that BACT control for mercury is injecting activated carbon or sodium sulfide upstream of a baghouse.

GCP is considered BACT for CO. The preliminary CO emission levels estimated for the plant in Table 19 seem high, considering that both permitted emission limits shown in Table 20 for RDF CFB are 100 ppmvd. Furthermore, the emission limit in the draft NSPS is 100 ppmvd. CO catalysts exist for CO control, but they would probably not be required in a future biomass-to-ethanol plant (except possibly in states with extreme CO attainment problems).

A standard of no visible fugitive fly ash/bottom ash emissions from ash handling (e.g., ash storage facilities and transfer points) would apply to all size facilities. MACT is required for fugitive emissions and would consist of fugitive emission controls on all ash conveyors, conveyor transfer points, storage facilities, and ash loading to trucks or containers. Control measures would include enclosing any outdoor ash transfer areas and ventilating emissions to a control device; other ash handling activities would require watering ash to prevent fugitive emissions.

The facility would require a PSD permit, including BACT review; this would be administered by the state air quality agency or a local air pollution agency. Included in the permitting process would be an air quality dispersion modeling analysis to predict ambient concentrations of pollutants at the ground level. Some states would also require a simplified risk analysis, whereby the results of the air quality dispersion analysis for toxic pollutants such as cadmium would be plugged into a simplified risk assessment formula to ensure estimated cancer risks were below a common threshold (typically a one in a million risk). This type of analysis can be the determining factor for the actual stack height of a facility.

Solid Waste

The acetaldehyde and fusel oils combusted in the boiler would be assumed to be less than 1% of the total fuel requirement for the boiler on a total heat input or mass input basis, whichever results in the lower mass feed rate of hazardous waste. Based on this assumption, which process designers should strive to meet to avoid full BIF regulatory status, no major solid waste permits would be required, although EPA would have to be notified of the type and amount of hazardous waste being combusted. State regulators could require more stringent review of the combustion process for acetaldehyde, but they probably would not because it would be redundant with the PSD permit review. Because of its clean fuel properties, the biogas from the AD process would not be considered a hazardous ignitable waste.

Ash residue from a CFB combusting nonreacted solids from the post-fermentation process of RDF should not be considered a hazardous waste by EPA. Historically, bottom ash from MWCs has passed EPA's TCLP test (for determining whether a waste is hazardous); fly ash, however, has often failed the TCLP, but the combination of bottom ash and fly ash has usually passed. Data on ash from the Gotaverken RDF-fired CFB boiler at Sundsvall, Sweden are shown in Table 22 (Minott 1991). (The data are based on the EP toxicity test, the original test for determining hazardous characteristics; it has been superseded by the TCLP test.)

The ash testing data are unusual because both the bottom ash and fly ash pass the EP toxicity test. The waste in Sweden could contain fewer heavy metals and be the reason the fly ash passes the EP toxicity test, but there could be other reasons. Minott (1991) suggested that the longer residence time in the bed allows metals to fix onto silica and limestone more than in other MWCs and resist the leaching environment in the EP toxicity test better than other fly ash. Additional testing is required to understand fly ash formation in CFB combustors. This analysis assumes the ash is nonhazardous and can be disposed in a landfill or MWC.

Total ash that would be sent to a landfill for the base case is shown in Table 23.

Water

Liquid effluent releases for the base case are shown in Table 23. The liquid effluent from the aerobic reactor is assumed to be sent to a POTW. The treated wastewater will contain dissolved solids (minerals, nutrients, and gypsum) and unconverted organic material (lignin). The system is designed to achieve discharge levels of 300 mg/L BOD, 600 mg/L COD and 300 mg/L TSS (CH2M Hill 1991), which are within the requirements for POTWs.

Scenario B—Landfill or Dispose of Wastes in Off-Site MWC

The environmental releases from Scenario B—the fermentation off gases, tank losses, and wastewater release—will generally be the same as those for the base case. The volume of acetaldehyde produced will also be the same; however, it will require disposal because there is no boiler. To minimize the volume of solvents that require disposal, the fusel oils will be blended into the ethanol product as is commonly done in the corn ethanol industry. Fuel ethanol can have up to 2 vol % impurities (ASTM D4806-88); including the fusel oils would be less than 0.5 vol % impurity.

Scenario B is very easy to analyze from an environmental standpoint. No major air permits would be required, although VOC process emissions such as ethanol, which would be similar to the base case, would have to be controlled, and a local or state air permit would probably be required.

All wastes left from the process, approximately 77,540 tpy, would be landfilled. (The weight of this waste could be lowered significantly to reduce off-site disposal costs because it consists of 50% moisture content.) This waste is assumed to be nonhazardous. Acetaldehyde would be collected on-site in a large tank and manifested (an EPA term for the slip of paper that accompanies a hazardous waste from cradle to grave) for off-site shipment via a hazardous waste hauler. A tanker would unload the fuel three to four times a week and deliver it to an RCRA permitted treatment, storage, and disposal facility, where it would be blended in with other fuels and combusted. A large on-site tank would be required to store the large amounts of acetaldehyde generated. The tank capacity would have to be designed to accommodate storage in case the hazardous waste hauler missed a shipment.

Water treatment would be similar to the base case, except that AD would not be included; hence, no methane would be produced.

Table 22. EP Toxicity Test Results for Gotaverken CFB Residues[1]

Pollutant	EPA Allowable Limit (ppm)	Bottom Ash (ppm)	Fly Ash (ppm)
Arsenic	5.0	.007	.17
Barium	100.0	.1	.3
Cadmium	1.0	.05	.03
Chromium	5.0	.12	.04
Lead	5.0	.35	.04
Mercury	0.2	.0002	.001
Selenium	1.0	.01	.02
Silver	5.0	.04	.02

[1] Sundsvall CFB facility that burns RDF with EPS and in-furnace limestone scrubbing.

Scenario C—Anaerobic Digestion of all Wastes

Air emissions for this scenario are very similar to the emissions for the base case, except for SO_2 emissions, which are estimated at 832 ppmvd as opposed to 190 ppmvd in the base case. The higher SO_2 emissions are caused by the calcium sulfate solids (gypsum) forming from the calcium (from the limestone) reacting with the sulfur from the fuel are not separated out before AD. Instead, they are digested, and release the sulfur when the solids from the wastewater treatment are combusted.

The BACT needed for this scenario would be the same as the base case (see Table19), although higher rates of lime use would be required for the dry scrubber to control SO_2 emissions. In fact, it could not be determined whether the SO_2 standards would be obtainable with a dry scrubber for such high uncontrolled SO_2 emissions. A wet scrubber, such as a venturi followed by a packed tower, may be needed to obtain the higher acid gas control.

Solid waste and liquid effluent issues would be the same as the base case, except that solids would be disposed of in the boiler.

Boiler size would be about the same as in the base case; hence, a PSD permit would be triggered by NO_x and CO emissions as in the base case. PSD would also be triggered for SO_2 emissions.

Scenario D—Gasifying all Wastes

Table 24 shows the estimated emissions, corresponding federal regulations, BACT estimates, and assumed APC efficiencies for Scenario D. Stream numbers refer to the process flow diagram in Figure 5. Stream 4a is from the gasification process and stream 4b is from the gas turbine. Because gasification of MSW is not a fully commercialized technology, BACT estimates are very preliminary.

This scenario does not contain a CFB reactor, so emissions are significantly lower than Scenarios A and C. Combined NO_x emissions (PSD thresholds are measured on a total plant basis) are 228 tpy, assuming SNCR for the gasification process (just less than the 250 tpy PSD threshold). Uncontrolled SO_2 emissions would be 267 tpy, so APC would be needed to avoid the SO_2 PSD (a PSD review would require a BACT analysis and APC for SO_2). APC would also be needed for particulates.

Table 23. Ash and Water Releases for Base Case

Component	Stream 5 Ash to Landfill (16/h)	Stream 6 Effluent to POTW (16/h)
Water		400,581
Soluble Solids		0
Ash	25,497	0
Sugars		4
HMF		1
Furfural		14
Gypsum	577	328
Cellulase		4
Glycerol		27

Two types of APC systems could be used for the gasification system: a wet scrubber or some type of dry scrubber (either limestone injection upstream of a baghouse or a spray dryer upstream of a baghouse). The wet scrubber can achieve higher acid gas control as compared to dry injection upstream of a baghouse, whereas either type of dry scrubber can achieve lower particulate emissions than a venturi scrubber. (Some venturis can achieve particulate emissions as low as baghouses, but the electricity needed for the fan to supply the high-pressure drop can be expensive over the life cycle of the system. This type of comparison also depends on the type of material used in the FFs). Either scrubber system could work, and final selection would depend on costs and system design preferences. An RDF pyrolysis reactor in Greve, Italy, uses a dry scrubber for APC (Dhargalkar 1991).

Because MSW gasification plants are mostly still in the pilot plant phase, there are few emissions data from existing facilities. Table 25 shows preliminary (and incomplete) emissions data for some MSW pyrolysis plants; APC equipment is also noted.

Because gas turbine operation is extremely sensitive to particulates and acid gases, the gas entering the turbine would have to be "cleaned" to very high standards; hence, the acid gas and particulate emissions from the gasifier would not be of concern from an environmental permitting standpoint. Because this equipment would be required for the system design, it is not considered in the APC equipment cost estimates.

Char from the gasification process would have to be disposed in a landfill. Test results on facilities indicate this material would pass EPA's TCLP test and not be considered a hazardous waste. Test results for metals from MSW gasification char may be found in Yasui and Masuda (1984).

There are a number of benefits to Scenario D from an environmental regulatory standpoint. With appropriate APC equipment, a 2000-tpy facility would need only a state air permit (not a PSD permit). However, a few states have stricter regulations and could require a PSD permit (e.g., Connecticut has a 100-tpy PSD threshold) or a state permit that could contain some of the requirements of a PSD permit (e.g., air quality dispersion modeling). A further benefit of Scenario D is that it would have less chance of being perceived as a waste-to-energy facility because the MSW would not be combusted.

Base Case with Agricultural Residues

Non-boiler emissions, such as process emissions from fermentation, would be approximately the same as for the base case for MSW feedstocks. Table 26 shows the emissions, estimated BACT requirements, corresponding federal regulations, and assumed APC efficiencies for the base case with agricultural residues as a feedstock. BACT for NO_x is estimated to be SNCR, whereas BACT for particulates is estimated to be a baghouse. BACT for SO_2 is considered to be limestone injection in the CFB with subsequent capture of particles in the baghouse. A PSD permit would be required because NO_x and CO emissions would exceed PSD thresholds. For reference, emissions from CFB facilities combusting agricultural residues are shown in Table 27.

Summary of Permitting Requirements

Table 28 shows a preliminary summary of the PSD permitting requirements for the base case for MSW and agricultural residue feedstocks. Also shown are the results for a 1000-tpd and 3000-tpd plant. All volumetric pollutant emission rates would be assumed to scale linearly according to capacity size for the 1000-tpy and 3000-tpy plant.) The type of APC equipment used in the emissions estimates is also shown.

Comparison of Environmental Requirements for New and Existing Boiler Facilities

There are a number of reasons a biomass-to-ethanol facility might want to use an already permitted facility for combusting wastes. The primary reason is siting, as siting any type of facility that combusts MSW or its by-products can be problematic. Using a permitted MWC would mitigate potential siting problems. In addition, an MWC could benefit from the volume reduction offered by a biomass-to-ethanol facility, thereby greatly increasing the total amount of waste a plant could receive.

Current emissions standards are more lenient for existing facilities, but the difference in the pollution control requirements and associated costs between existing and new facilities is apparently too small to warrant using such a facility based solely on APC costs; hence, using an existing MWC could not be justified based on environmental requirements. However, siting could be a potential justification, and should be studied further.

Table 24. Emissions for Gasification Scenario

		MSW Base Case D - 2000 TPD New Facility								
		70 366	MMBtu/h-combustor MMBtu/h-turbine							
	Stream #	Pollutant/	Uncontr. Emission (ppmvd)	Uncontr. Emission (lb/MMBtu)	Uncontr. Emission mg/dscm	Federal Standard[a]	BACT Estimate[c]	Removal Efficiency	Controlled Emission Rate	tons/yr
air	1	EtOH - VOC	57		110	none	CTG			14
	2	VOCs			na	none	CTG			2
	4a	NO^x	186	0.400	357.000	180 ppm	SNCR	65%	65 ppmvd	40
		SO_2	310	0.924	825.000	30 ppm/80%	Wet/Dry	80%	62 ppmvd	53
		PM-10**	na	0.030	2700	34 mg/dscm	Wet/Dry	99%	27 mg/dscm	9
		Lead	1.19E-03	1.15E-05	0.010	0.16 mg/dscm	Wet/Dry	0	0.0103 mg/dscm	<1
		CO	114	0.150	135.000	100 ppm	GCP	0	114 ppmvd	44
		VOCs/HC	34	0.025	22.000		GCP	0	1.65 lb/hr	7
		acetaldehyde	0.19	3.86E-04	0.340	1.0%[(b)]	GCP	0	1.13%	1
		formaldehyde	0.18	2.48E-04	0.220	NA	GCP	0	na	<1
	4b	NO_x	42	0.018	81.000	75	GCP	0	42 ppmvd	188
		SO_2	80	0.309	212.000	50 ppm/2.5 lb/MMBtu	none			<1
		PM-10	negligible	negligible	negligible		none			<1
		Lead	0	0.000	0.000		none			<1
		CO	10	0.016	11.000		none			26.3
		VOCs	5	0.005	3.300		none			7.8

(a) Stream 4a is based on draft NSPS MSW combustor limits, 4b on NSPS gas turbine regulations.
(b) BIF regulations allow maximum firing rate of 1% of total fuel requirements based on BTU or mass basis, whichever results in lower feed rate
© Wet/Dry - wet or dry scrubber; SNCR - Selective non-catalytic reduction; CTG - Control technology guidelines; GCP - Good combustion practice

Table 25. Emissions Data from Pyrolysis Plants

Pollutant	Greve, Italy Facility (Dhargalkar 1991)[1]	Chichibu City Facility (Yasui and Masuda 1981)[2]	Tsukishima Kikai Facility (Igarashi and Hayafune 1984)[2,3]
SO_x	NA	29 ppmv	17 ppmv
NO_x	NA	142 ppmv	83 ppmv
HCl	18 ppmvd (30 mg/nm^2)	NA	92 ppmv
PM	0.0023 gr/dscf (5 mg/nm^2)	0.04 m^{3}N (Note units)	NA
Mercury	NA	NA	NA

1 Includes dry scrubber
2 Includes ESP
3 Includes both regenerator flue gas and gas-fired boiler flue gas. Low NO_x is from catalytic de-NO_x reactor installed for the gas-fired boiler exhaust gas

Costs for Pollution Control Equipment

Preliminary costs for acid gas and particulate control APC equipment (EPA 1987) and SNCR (Hurst and White 1986) are tabulated in Table 29. These costs are not for CFB boilers; very few data are available for APC equipment for CFB boilers.

No life-cycle costing calculations were conducted for the various scenarios. These calculations could be included in future work efforts; however, they would require additional process engineering costs (e.g., gasifier/gas turbine costs) to facilitate a realistic comparison of the scenarios discussed in this report.

Certain information can be ascertained from the limited cost data available. For example, waste disposal costs for Scenario B are estimated at $27 million/year (@ $50/ton for disposal). These costs seem prohibitive, considering that no revenue would be created from electricity sales. There is no advantage to Scenario C in terms of APC costs. There is an advantage to the base case with agricultural residues because the limestone injection in the CFB would be significantly cheaper than the spray dryer costs for MWCs. However, without conducting a detailed life-cycle cost analysis of the entire system, including electricity sale revenues, a final cost comparison for the scenarios cannot be made.

Table 26. Emissions for the Base Case with Agricultural Residues

		Agricultural 2000 tpd New Facility						
		574	MMBtu/h					
Regulatory Classification	**Stream #**	**Pollutant**	**Uncontrolled Emission (lb/MMBtu)**	**Federal Standard**	**BACT Estimate**	**Removal Efficiency**	**Controlled Emission Rate**	**tons/yr**
air	1	EtOH - VOC	na		CTG		3.6 lb/h	16
	2	VOCs	na		CTG		0.53 lb/h	2
	5	NO^x	0.400	0.6 lb/MMBtu[1]	SNCR	65%	0.14 lb/MMBtu	383
		SO_2	0.528	1.2 lb/MMBtu[1]	CFB/Lime	80%	0.10 lb/MMBtu	289
		PM-10*	0.030	2.4 lb/MMBtu[1]	FF	99%	0.024 lb/MMBtu	82
		Lead	7.96E-06	na	CFB/Lime	90%	.79E-06 lb/MMBtu	<1
		CO	0.150	PSD - 250 tpy	GCP	0	0.150 lb/MMBtu	411
		VOCs	0.025	PSD - 250 tpy	GCP	0	0.025 lb/MMBtu	68
		acetaldehyde	3.86E-04	none		0	3.86E-04	1
		formaldehyde	2.48E-04	none		0	2.48E-04	1
solid	3	acetaldehyde	na	1% BIF-NA[2]			1.03%[2]	
waste		fusel oils	na	BIF-NA			na	
	6	ash	na	TCLP				

1 NSPS for steam-generating units
2 BIF regulations allow maximum firing rate of 1% of total fuel requirements based on BTU or mass basis, whichever results in lower feed rate

Table 27. Emissions from Existing CFB Facilities Combusting Agricultural Residues (Maitland and Mylchreest 1992).[1]

	Fresno, CA	Rockland, CA	Colmac, CA
Primary Fuels	Inforest, mill waste, urban dunnage, agricultural prunings	Inforest, mill waste, urban dunnage, agricultural prunings	Mill waste, muni-ag waste, agricultural waste
Particulate control	ESP	ESP	Baghouse
NO_x Control	NH_3 injection	NH_3 injection	NH_3 injection
SO_x control	None	None	Limestone
NO_x emissions (lbs/h)	27.5	52.2	30
SO_x emissions (lbs/h)	34.0	31.0	12
CO emissions (lbs/h)	22.0	52.2	45
HC emissions (lbs/h)	9.5	8.5	10
Particulate emissions (lbs/h)	0.010	0.016	0.010

1 Fresno and Rockland plants are 24.3 MW_e, the Colmac plant is 49 MW_e net. Emissions are guaranteed permit limits.

Table 28. APC and PSD Permitting Summary

Configuration/Feedstock/Size	PSD Required	Pollutants > 250 tpy	APC Assumed
Base Case - MSW - 1000 tpy	No	--	SNCR, SD/FF
2000 tpd	Yes	No_x, C0	SNCR, SD/FF
3000 tpd	Yes	No_x, CO	SNCR, SD/FF
Scenario B - MSW - All sizes	No	--	--
Scenario C - MSW - 1000 tpd	Yes	SO_2	SNCR, SD/FF
2000 tpd	Yes	No_x, CO, SO_2	SNCR, SD/FF
3000 tpd	Yes	No_x, CO, SO_2	SNCR, SD/FF
Scenario D - MSW - 1000 tpd	No	--	SNCR, DI/FF[1]
2000 tpd	No	--	SNCR, DI/FF
3000 tpd	Yes	Combined No_x	SNCR, DI/FF
Base Case - Agricultural Residue 1000 tpd	No	--	Limestone inj/FF[2]
2000 tpd	Yes	No_x, CO	Limestone inj/FF
3000 tpd	Yes	No_x, CO, SO_2	Limestone inj/FF

1 Limestone injection upstream of FF
2 Limestone injection in CFB with fabric filter

Table 29. Preliminary APC Equipment Costs (1000$—1990)

APC Equipment	Capital Cost ($)	Annualized Cost ($)
Spray Dryer/Baghouse - 1000 tpd @ 0.01 gr/dscf	10628	2989
Spray Dryer/Baghouse - 3000 tpd @ 0.01 gr/dscf	26053	7680
SNCR	800	500

Environmental Siting Issues for the Scenarios Analyzed

Background

Siting constraints may increase the time and cost of the siting process, delay bringing a facility on line, or even prevent it from ever operating. A biomass-to-ethanol facility must go through the increasingly difficult process of siting. The requirements for siting a biomass-to-ethanol facility depend on a number of factors, including the size of a facility, feedstock type, permitting requirements, location, proximity to feedstocks, cost of power, and a number of other site-specific facility and community characteristics. This discussion addresses only those issues that relate to environmental requirements.

Depending on NEPA and regulatory permit requirements for a facility (determined by the environmental regulations discussed in the Regulatory Analysis section), the public may or may not have a formal participatory role included in the siting process. For example, EIS requirements include mandatory public hearings, but PSD permits do not. The degree of public participation in the regulatory review process can significantly affect the overall siting process. Regulatory review and public participation in siting processes are connected; the regulatory process often determines the degree of planned public involvement, and the amount of public involvement directly affects the siting process. The effect of regulatory review and public participation on siting are discussed below.

Impact of Regulations on Siting Biomass-to-Ethanol Facilities

Regulatory requirements for biomass-to-ethanol facilitates were discussed in depth. The primary regulatory parameters that affect siting of a biomass-to-ethanol facility include attainment classification, state and local permit requirements, and NEPA determination. Both attainment classification and permitting affect siting because they determine the specific air quality standards a facility must meet and whether pollutant emissions must be offset. Because state and local permit requirements vary so much throughout the United States, they cannot be compared in this report. Table 30 shows examples of the effects these two parameters can have on siting.

NEPA requirements for a biomass-to-ethanol facility could vary depending on who built the facility and where it was built. Whenever possible, an EIS should be avoided because it is the most common method for a community to hold up a project. Although an EIS may not be required for a project based on NEPA review, it has been required in some cases on political grounds. For example, the refiring of the Tacoma steam plant in Washington, a fluidized bed boiler combusting RDF, coal, and wood, did not originally trigger an EIS. However, pressure from the community resulted in politicians requiring that an EIS be conducted. The utility could have sued because the original NEPA review stated that no EIS was required; however, a lawsuit would have tied the project up more than the EIS requirements.

Public Opposition and the Siting of Energy Projects

A detailed discussion of public opposition and its impact on siting energy facilities is beyond the scope of this document. However, it is briefly discussed because of its potential impact. Most often, disagreement over the relative costs and benefits of a particular facility at a particular site is a source of a public siting constraint. Another source could be organizational or institutional factors, especially when the organizations involved cannot function effectively or cooperatively (DOE 1993).

Siting case studies for energy facilities usually recommend bringing the public into the decision-making process early and working with the public as much as possible when public opposition is perceived to be an issue (NREL 1993). Unfortunately, the response of the public is not always rational, and the not-in-my-backyard syndrome sentiment can create momentum during the course of public participation in the review of a project.

Table 30. Example of Location on Environmental Siting Requirements

	Examples of Effects on Siting of State Permitting and Attainment Classification		
Parameter	**Extreme Example**	**Moderate Example**	**Low Impact Example**
State regulations	State solid waste regulations require all facilities that burn hazardous waste (e.g., acetaldehyde) to meet BIF regulations (i.e., permitting requirements similar to hazardous waste incinerator)	State air regulations require PSD permit for all facilities > 100 tpy of any criteria pollutant	State air permit does not require any air quality modeling and no state BACT review is required
Attainment Classification	Facility cannot be sited because pollutant offsets are not available	Facility requires additional control technologies (i.e., LAER) to achieve stringent emission limits	Facility must meet BACT

MSW biomass-to-ethanol facilities have a number of siting issues on their side compared to MSW waste-to-energy facilities. Most importantly, an MSW biomass-to-ethanol facility should not be regulated as an MSW incinerator; this classification should help, because the public has shown a deep skepticism toward any type of incinerators, especially those that combust MSW. A second favorable point is that biomass-to-ethanol facilities can be perceived as renewable energy facilities, and the public has shown a favorable attitude toward renewable energy from an environmental standpoint. This is especially important because the strongest opponents of waste-to-energy facilities in the past have been environmentalists.

The scenarios and feedstocks analyzed in this report could be perceived differently by the public. Some of these perceptions are listed in Table 31.

Summary

This report presents an in-depth environmental regulatory analysis for several process configurations of biomass-to-ethanol facilitates. The environmental regulatory analysis for these facilities is very complex, because hundreds of regulations affect them; hence, this analysis has focused only on those estimated to have the greatest impact. In conjunction with the regulatory analysis, emissions for the scenarios were presented, and the associated pollution control equipment discussed. Existing ethanol plants were reviewed in terms of their environmental impacts and permit requirements.

A PSD permit was identified as the primary environmental permit that would be required for most scenarios. In most cases, a biomass-to-ethanol facility would probably not require an EIS, although this would have to be determined case-by-case. Permitting requirements for O_3 nonattainment areas were also identified as important to consider.

In general, permitting and siting an MSW biomass-to-ethanol facility should not be as difficult as permitting and siting an MSW waste-to-energy plant. Fundamental differences exist in the regulatory status of these processes. The primary difference is that biomass-to-ethanol facilities would not be considered MWCs under federal regulations, but would instead be regulated as a manufacturing process. It is recommended that biomass-to-ethanol facilities still meet all regulations for MWCs to ensure regulators that environmental impacts from these facilities will be as low as possible.

Table 31. Potential Public Perceptions Associated with Various Scenarios

Scenario	Preliminary Comments on Siting and Public Opposition
Base Case- MSW	EPA regulatory classification is an industrial process, not an MSW incinerator. Perception as a hazardous waste incinerator (because of acetaldehyde combustion and BIF regulations) should be avoided.
Scenario B - MSW	Because there are very few emissions from this process, public opposition and siting should not be a problem.
Scenario C - MSW	Same as base case - MSW.
Scenario D - MSW	This process could be perceived as a clean way of disposing of MSW, as it would not be regulated as a combustor. Furthermore, it would have lower emissions than the base case, and for some plant sizes would not trigger a PSD permit.
Base Case - Agricultural Residues	Public opposition would be the least for this scenario because wood waste is usually perceived as being clean and renewable (compared to MSW).

As biomass-to-ethanol facilities move closer to commercialization, it will be important to continue to characterize the expected emissions from these facilities and any changes in the environmental regulations. Work could include the following:

- Emissions testing at pilot plant facilities
- Further refining the estimated emissions from plants that use different feedstocks
- Presenting environmental papers on biomass-to-ethanol facilities at conferences to introduce the environmental community (including regulators) to the process
- Further analyze the economic impacts of the pollution control, permitting, and siting requirements for biomass-to-ethanol facilities
- Further discussions with EPA on the environmental regulations for biomass-to-ethanol facilities.

It is especially important to calculate better emissions data on biomass-to-ethanol facilities, because if emissions data are not available, very conservative emission estimates will be required to permit any facility (such as emissions estimates from conventional RDF facilities), which could lead to misunderstandings regarding the actual emissions from biomass-to-ethanol facilities.

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Appendix A

Summary of Future Clean Air Act Studies and Regulatory Developments That Could Affect Biomass-to-Ethanol Facilities

CAAA-90 Title and Section	Subject	Performing Organization	Original EPA Deadlines	Comments/Details
TITLE III Section 301 Air Toxics/ HAPs	Residual risk matters	EPA	11/15/96	The Administrator must consult with the Surgeon General and report to Congress on public health risks after MACT standards are applied. Will set basis for further regulations after MACT.
TITLE III Section 301 Air Toxics/HAPs	Offsets	EPA	11/15/92	Publish guidance on meeting offset requirements, including identification of the relative hazard to human health resulting from emissions of HAPs.
TITLE III Section 301 Air Toxics/HAPs	Urban strategy. Air source program.	EPA	11/15/95	The Administrator must report to Congress on a strategy for dealing with HAPS emitted by sources in urban areas with populations more than 250,000. The strategy must identify at least 30 pollutants that present the greatest health threat and identify their source categories.
TITLE III Section 301 Air Toxics/HAPs	Emissions of HAPs by electric utility steam-generating units.	EPA	11/15/93	Regulation to follow study if appropriate after considering study results.
TITLE III Section 301 Air Toxics/HAPs	Emissions of mercury by electric steam-generating units.	EPA	11/15/94	Study to consider utility power plants, MWCs, other sources, and area sources. Study to consider emission rates, health and environmental effects, control technologies, and their costs.
TITLE III Section 301 Air Toxics/HAPs	Carcinogenic risk associated with exposure to HAPs from source categories.	NAS	5/15/93	NAS to begin study 2/15/91 on HAP carcinogenic risk assessment methodologies and adverse health effects.

CAAA-90 Title and Section	Subject	Performing Organization	Original EPA Deadlines	Comments/Details
TITLE IV **Section 411** Buffering and Neutralizing Agents	Study of buffering and neutralizing agents.	Dept. of Interior U.S. Fish and Wildlife Service	N/A	Study of the effectiveness of buffering and neutralizing agents used to restore lakes and streams damaged by acid deposition.
TITLE VI **Section 618**	Natural sources	EPA	11/15/92 Report to Congress	Methane emissions from biogenic sources such as tropical, temperate and subarctic forests, tundra, and freshwater and saltwater wetlands.
TITLE VI **Section 618**	Methane studies—domestic methane source inventory and control, Report to Congress.	EPA, DOE, USDA	11/15/92 Report to Congress	Methane emissions from: • Natural gas and coal extraction, transportation, distribution, storage, and use • Management of solid waste storage, treatment, and disposal • Agricultural production • Biomass burning—intentional burning of agricultural wastes, wood, grasslands, and forests • Human activities
TITLE VIII **Section 816**	Research to identify and evaluate source regions of visibility impairment. Applies to Class I regions, such as the Grand Canyon National Park	Visibility Transport Commission established by 11/15/91 EPA National Park Service	11/15/94 Report to EPA	Establish visibility transport regions. Assess data and information pertaining to impacts on visibility.

CAAA-90 Title and Section	Subject	Performing Organization	Original EPA Deadlines	Comments/Details
TITLE IX **Section 901** Clear Air Research	Conduct research program on the short-and long-term effects of air pollutants, including wood smoke, on human health.	EPA Secretary of Health & Human Services	11/15/91 Determine priority Annually—publish no less than 24 assessments 11/15/91 Every 4 years thereafter	Conduct studies as necessary to identify and evaluate exposure to and effects of air pollutants. Use Federal scientific laboratories and research facilities. Create an Interagency Task Force to coordinate the program. The National Institute of Environmental Health Sciences (NIEHS) will perform similar research coordinated with the program stressing human health effects.
TITLE IX **Section 901** Clean Air Research	Conduct research to improve understanding of short- and long-term causes, effects, and trends of ecosystem damage from air pollutants.	EPA, USDA, DOC, Fish and Wildlife Oceans and Atmosphere	N/A	Identify critical ecosystems. Develop improved models. Evaluate pollutant effects on water quality, forests, crops, and soils, and estimate economic costs of damage.
TITLE IX **Section 901** Clean Air Research	Clean Alternative Fuels Research.	EPA	N/A	Identify, characterize, and predict emissions related to producing, storing, and using alternative fuels, and determine risks and benefits to human health and environment. EPA will consult with other agencies.

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